EMISSIONS, COSTS AND ENGINEERING ASSESSMENT
WORK GROUP 3B

UNITED STATES — CANADA

MEMORANDUM OF INTENT ON TRANSBOUNDARY AIR POLLUTION

FINAL REPORT
JUNE 1982

WORK GROUP 3B

EMISSIONS, COSTS AND ENGINEERING ASSESSMENT

FINAL REPORT

Work Group Co-Chairmen

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Report No. 3B Final
June 15, 1982

Submitted to the Coordinating Committee in fulfillment of the requirements of the Memorandum of Intent on Transboundary Air Pollution signed by Canada and the United States on August 5, 1980.

PREFACE

This is a final report prepared by the United States/ Canada Work Group on Emissions, Costs and Engineering Assessment in accordance with the Memorandum of Intent on transboundary air pollution concluded between Canada and the United States on August 5, 1980.

This report is one of a set which draws together currently available information on transboundary air pollution with particular emphasis on acid deposition. The reports provide a unique compendium of currently available information and represent a consensus within the United States/Canada scientific community on the nature of the problem and the technologies available to deal with it. They reflect the current state of scientific knowledge and suggest further research needed to refine the state of that knowledge.

The Office of the Science Adviser to the President in the United States and the Royal Society of Canada are conducting peer reviews of these reports to be completed later this year.

June 15, 1982

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Deputy Assistant Secretary for
European Affairs
Department of State
Washington, D.C.
20520

Mr. Edward Lee
Assistant Under Secretary
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Dear Mr. Niles and Mr. Lee:

We are pleased to submit a report summarizing the Phase III activities of Work Group 3B. This report represents a collaboration by technical experts in our two countries to provide useful information under the terms of reference. We hope that the information contained herein will be of benefit to you in the negotiating process.

Yours sincerely,

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WORK GROUP 3B
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PREAMBLE

The Emissions, Costs, and Engineering Assessment Subgroup (Work Group 3B) was established under the MEMORANDUM OF INTENT in order to provide support to the development of the control element of a bilateral agreement on transboundary air pollution. Work Group 3B is also charged with preparing proposed work under the Applied Research and Development element of the agreement.

The purpose of this Phase III report is to respond to the Terms of Reference identified in the MEMORANDUM OF INTENT and to the tasks set forth in the group's approved work plan.

During Phase I, Work Group 3B devoted its efforts to:

a) Preparing a work plan for Phase I and Phase II

b) Identifying control technologies and associated costs for source categories of major concern

c) Reviewing historical emission trends

d) Determining current emission rates from the source regions

e) Projecting future emission rates

f) Preparing the Phase I report

During Phase II, the group accomplished the following:

a) Refined initial data inputs

b) Prepared a work plan for Phase III

During Phase III the group:

a) Improved and expanded on the information compiled in previous studies

b) Undertook a more careful examination of uncertainties

c) Completed a formal Phase III report (this report).

The first chapter of this report summarizes the major findings and conclusions in terms of the major analytical elements: emissions, technology for control, and costs. The remainder of the report is structured to closely follow the Terms of Reference for Work Group 3B. Chapter B analyzes the emission trends for SO_2 and NO_x in the United States and Canada. Chapter C presents data and information on emission control technologies and associated costs for all major source categories. While Chapter D presents preliminary data on other pollutants,

(SO_4, volatile organic compounds (VOC) and heavy metals). A discussion of the constraints on and boundaries of analysis is presented in Chapter E. The final chapter of this report lays out the present and planned research activities of the two countries and suggests some future research and development needs.

The Terms of Reference and the membership of Work Group 3B are found in Appendix 1 of this report.

The other Appendices present more detailed information on the methodologies used to calculate the emission inventories and future emission projections, and the emission inventory for 1978 used by Work Group 2 in its modelling work. Control technologies for SO_2 abatement and current Research and Development projects are also described in more detail.

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CONVERSION FACTORS

kilo = 10^3
mega = 10^6
giga = 10^9
tera = 10^{12}

1 ton = 0.907 metric tons (tonnes)
1 lb = 0.454 kilogram

1 Btu = 1055 joules
1 quad = 10^{15} Btu

1 gal (U.S.) = 3.785 litres
1 barrel = 159 litres

1 lb/10^6 Btu = 430 ng/J

1 Btu/lb = 2.324 joules/gram

Costs basis = U.S. $(1980)

U.S. $(1979) = 0.915 U.S. $(1980)

Can $(1980) = 0.86 U.S. $(1980)

GUIDE TO ABBREVIATIONS

ABMA	American Boilers Manufacturers Association
AQCR	Air Quality Control Region
ASM	Annual survey of Manufacturers
BEA	Bureau of Economic Analysis
BNL	Brookhaven National Laboratory
CCC	Chemical Coal Cleaning
CEA	Canadian Electrical Association
CM	Combustion Modification
CO	Carbon Monoxide
DCDA	Double Contact Double Absorption
DMA	N, N-dimethylaniline, (an organic liquid)
DOE	Department of Energy (United States)
EIA	Energy Information Administration (United States)
EHPA	E.H. Pechan Associates
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitators
ERCB	Energy Resources Conservation Board
ESFF	Electrostatically Stimulated Fabric Filtration
FBC	Fluidized Bed Combustion
FCC	Fluid Catalytic Cracking
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
FGT	Flue Gas Treatment
FMVCP	Federal Motor Vehicle Control Program
FPC	Federal Power Commission (United States)
FRP	Fiber Reinforced Plastic
HATREMS	Hazardous and Trace Emissions System
HC	Hydrocarbons
HDD	Heavy-Duty Diesel
HDF	Heavy-Duty Fuel
HDG	Heavy-Duty Gasoline
HDT	Heavy-Duty Trucks
IBM	Industrial Boiler Model
IEA	International Energy Agency
IERL/RTP	Industrial Environmental Research Laboratory/Research Triangle Park, North Carolina
IORP	Iron Ore Recovery Plant
LDV	Light-Duty Vehicles
LDT	Light-Duty Trucks
LIMB	Limestone Injection Multistage Burner
LPG	Liquid Propane Gas
MDAD	Monitoring and Data Analysis Division
MFBI	Major Fuel Burning Installation File
NAAQS	National Ambient Air Quality Standards
NAP	Non-Attainment Policy
NEB	National Energy Board (Canada)
NEDS	National Emissions Data System (United States)
NEIS	National Emissions Inventory System (Canada)
NEP	National Energy Program (Canada)
NEPP	National Energy Policy Plan (United States)

NSPS	New Source Performance Standards
OAQPS	Office of Air Quality Planning and Standards (United States)
OBERS	Office of Business Economic Research and Statistics (United States)
OM	Operation and Maintenance
PAD	Petroleum Administration for Defense
PHM	Process Heat Model
POM	Polycyclic Organic Matter
PSD	Prevention of Significant Deterioration
RTP, NC	Research Triangle Park, North Carolina
SCSA	Single Contact Single Absorption
SEAS	Strategic Environmental Assessment System
SIP	State Implementation Plan
SRC	Solvent Refined Coal
TRI	Teknekron Research, Incorporated
TVA	Tennessee Valley Authority
USM	Utility Simulation Model
VMT	Vehicle Miles Travelled
VOC	Volatile Organic Compounds

A. SUMMARY OF FINDINGS AND CONCLUSIONS

A.1 INTRODUCTION

Reviewed in this report are emissions of pollutants that undergo transboundary transport, the currently available technologies (process and control), costs of their application for the reduction of SO_2 and NO_x emissions for both new and retrofit installations and research and development activities. The cost for control equipment is a function of the degree of control desired, and is greater for retrofit installations than for new installations. While no detailed intersectorial analysis has been carried out for control costs it would appear that on a per unit of reduction basis, SO_2 controls may be far more costly for certain sectors than others. In addition, the impact of imposing controls on industry may not be limited to control costs. The problems of raising large capital sums, the payback period, the effect of tax and incentive legislation and the difficulty of bearing annual costs will all require detailed examination in the development of optimal control strategies.

Emissions (historical, present and projected) are listed for the fossil-fuel-fired electrical generation sector (eastern U.S. and Canada), non-ferrous smelters (eastern Canada) and mobile sources (U.S. and Canada). These sectors, together with industrial, residential and commercial fuel combustion, account for the majority of anthropogenic SO_x and NO_x emissions in the eastern part of North America, and hence are judged to be the most important sources in the acid precipitation problem. A brief review is carried out for petroleum refining, solid waste incineration and the pulp and paper industry. These sectors are considered to be of secondary importance to the acid precipitation problem since their emissions of SO_x and NO_x are considerably smaller in magnitude than those of the three primary sectors. A preliminary estimate of the emissions inventory for certain other air pollutants including primary sulfates, volatile organic compounds and selected metals is also provided.

To date, regulatory activity has been centered on maintaining and improving local and regional air quality. From the emission projections contained in this report it appears that between 1980 and 2000, SO_2 emissions will increase 7.6%; NO_x emissions will increase 26%. For the eastern portion of the U.S. and Canada (26 states east of the Mississippi River and provinces from Manitoba eastward) SO_2 emissions will decrease by 1% while NO_x emissions will increase by 38%. For certain source sectors and certain emitting regions increases in emissions may be significant.

Research & Development for SO_x and NO_x control for combustion sources is currently centered in three principal areas of activity; improvement in flue gas desulfurization technology, combustion modifications and fluid-bed combustion. It is considered that this research is necessary and should be supported to the maximum practicable extent. Some of these current initiatives may become commercially viable within the next 10 years; for example, combustion modifications offer the promise of relatively inexpensive NO_x control for coal-fired power plants.

A.2 EMISSIONS SUMMARY

Historical, present and projected emissions of sulfur dioxide and nitrogen oxides, and estimates of the probable error ranges around the present emissions in Canada and the United States have been developed. Emissions projections are based on baseline assumptions about economic and energy growth, assuming no changes in current environmental regulations. In addition, preliminary estimates of emissions of primary sulfates, volatile organic compounds and selected metals have been assembled.

Emissions of SO_2 in the U.S. rose from close to 20 million tonnes in 1950 to about 28 million tonnes in the mid-1960's before dropping to about 24 million tonnes in 1980. The southeastern and midwestern states shared the bulk of this increase. The southeastern states of Alabama, Florida, Georgia, Mississippi, Kentucky, North Carolina, South Carolina and Tennessee exhibited a sharp increase in SO_2 emissions between 1955 and 1978. The data suggest that this increase may be as high as three-fold, i.e. from about 2.1 million tonnes in 1955 to about 5.3 million tonnes in 1978.

In the midwestern states of Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin there appears to have been a significant steady increase in SO_2 emissions between 1955 and 1965 (from 6.6 million tonnes to 9.8 million tonnes) and a significant steady decline in these emissions since 1965 to 8.1 million tonnes in 1978. Levels today are about 25% higher than in 1955 in this region of the United States.

Total Canadian emissions of SO_2 were approximately 4.8 million tonnes in 1980, about the same level as in 1955, after having peaked in 1965 at close to 6.6 million tonnes. Eastern Canada, comprising the provinces east of the Manitoba-Saskatchewan border, contributed the bulk of these emissions, i.e. 4.3 million tonnes in 1955, 5.6 million tonnes in 1965 and 4.0 million tonnes in 1980.

Nitrogen oxides emissions in the U.S. increased significantly in all areas over the 1950-78 period. This increase ranged from about a factor of two in the northeast to over three in the south. The trend also indicates that total U.S. NO_x emissions have increased steadily from about 9 million tonnes to 20 million tonnes and did not peak in the mid-1960's as did SO_2. In the eastern U.S., emissions which were at a level of about 6 million tonnes in 1950 reached more than 17 million tonnes in 1978. Total NO_x emissions in Canada have increased from 0.6 million tonnes in 1955 to 1.8 million tonnes in 1980. Eastern Canada has contributed more than 60% to these emissions over this period.

During the 1978-80 period, yearly SO_2 emissions in North America (i.e. both U.S. and Canada) have amounted to close to 29 million tonnes. In eastern North America the total is close to 25 million tonnes, and the ratio of U.S. to Canadian emissions is 5.3 to 1.

Thermal power plants are the primary source of anthropogenic SO_2 emissions and contribute about 57% of the combined U.S.-Canada nation-wide emissions. This sector is followed by the industrial, commercial and residential fuel combustion category at about 14% of the combined nation-wide emissions. Then, at about 12%, are the emissions of SO_2 from non-ferrous smelters with all other industrial processes contributing about 13%. The primary contributor to present domestic SO_2 emissions differs in the U.S. and Canada. In the U.S. about two-thirds of the total domestic emissions comes from power plants, while in Canada more than 40% comes from non-ferrous smelters. About 16 million tonnes of SO_2 come from American power plants, about 2 million tonnes of SO_2 come from Canadian non-ferrous smelters. Only about 15% of the SO_2 generated in Canada comes from thermal power plants.

Yearly NO_x emissions in North America during the same period have amounted to about 21 million tonnes. In eastern North-America the total is about 16 million tonnes, while the ratio of U.S. to Canadian emissions in the east is roughly 15 to 1. About 45% of the combined nation-wide emissions comes from the transportation sector, about one quarter from power plants and about 20% from other combustion processes (industrial, commercial, residential, fuel combustion).

An analysis was performed to estimate the probable error inherent in the current emission estimates of SO_2 and NO_x. The probable errors are approximations derived through a combination of statistical theory and engineering judgement and do not represent true error values obtained through the application of rigorous statistical procedures.

The probable error in the national U.S. SO_2 emissions is estimated to be 2.3% and for NO_x, 2.0%. For Canada, the precision of the national SO_2 inventory was found to be 6.3% and for NO_x, 10.3%. For individual states or small regions, the probable error is higher.

In the next two decades total U.S. SO_2 emissions are projected to decrease slightly by 1990 to about 23 million tonnes from about 24 million tonnes in 1980 and then increase to about 27 million tonnes by the year 2000. Emissions from power plants are projected to remain roughly constant at about 16 million tonnes while emissions from the combustion of fuel in residential, commercial and industrial sectors is projected to increase from 3.2 million tonnes (1980) to 7.4 million tonnes (2000) or roughly 130%. The increase in emissions from the industrial sector is based on the assumption that there will be large increases in coal usage in industrial boilers. Emissions of SO_2 from U.S. non-ferrous smelters are projected to decrease to 0.5 million tonnes by the year 2000 from 1.4 million tonnes in 1980 as all non-ferrous smelters, due to existing regulatory requirements, must achieve approximately 90% reduction in SO_2 emissions from uncontrolled levels. However, non-ferrous smelters in the U.S are located in western and southwestern states and are therefore unlikely to play a significant role in the eastern North America acid precipitation issue. Emissions of SO_2 from other industrial processes are projected to decrease by about 50% by the year 2000 to about 1.5 million tonnes.

In Canada, total emissions of SO_2 to the end of the century are expected to decrease slightly from 4.8 million tonnes (1980) to 4.4 million tonnes (2000). Sulphur dioxide emissions from thermal power plants are expected to decrease slightly from 0.8 million tonnes in 1980 to 0.7 million tonnes by the year 2000. Although the emissions of SO_2 from power plants in Western Canada are projected to increase from about 80 kilotonnes in 1980 to close to 290 kilotonnes by the year 2000, this increase will be offset by decreases in SO_2 emissions in the Maritime Provinces and by decreases in SO_2 emissions from power plants in Ontario. Recent regulatory requirements announced by the Ontario government will limit the emissions of SO_2 from Ontario power plants to 260 kilotonnes/year by 1990 from the current 400 kilotonnes/year.

Sulfur dioxide emissions from industrial, commercial and residential fuel combustion are projected to decrease significantly from 0.8 million tonnes in 1980 to 0.25 million tonnes by the year 2000. The underlying assumption here, as reflected in the Canadian National Energy Plan (NEP), is the conversion to the use of natural gas from petroleum fuels.

Projected SO_2 emissions from Canadian non-ferrous smelting complexes to the year 2000 indicate a maximum of about 2.2 million tonnes per year, essentially the same level as in 1980. The level attained will depend on market fluctuations assuming no technological improvements are made at the various smelters. Emissions from other industrial processes are projected to increase from about 0.9 million tonnes in 1980 to close to 1.1 million tonnes by the year 2000. This increase is due primarily to an increase in SO_2 emissions in Western Canada based on the assumption that projected tar sands and natural gas development projects will proceed as scheduled. Recent events suggest that this assumption may no longer apply.

With respect to the emissions of NO_x to the year 2000, total U.S. emissions are projected to rise from about 19 million tonnes in 1980 to about 24 million tonnes by the year 2000. In Canada, the emissions are also projected to rise from about 1.8 million tonnes in 1980 to about 2.4 million tonnes by the year 2000.

An increase of about 55% in nitrogen oxides emissions is projected by the year 2000 from U.S. power generating stations, while in Canada the level is projected to be essentially the same as in 1980, i.e. about 250 kilotonnes. In the transportation sector, the emissions in the U.S. are expected to rise from about 8.5 million tonnes in 1980 to close to 10 million tonnes by the year 2000. In Canada, in the absence of further control action, NO_x emissions are projected to rise steadily from about 1.1 million tonnes in 1980, to 1.3 million tonnes in 1990 and to 1.7 million tonnes by the end of the century. Nitrogen oxides emissions both in Canada and the U.S. are projected to remain essentially constant from commercial, residential and industrial fuel combustion.

Present and projected SO_2 and NO_x emissions data for the U.S. and Canada are presented in Tables A.2.1 to A.2.4. As mentioned previously, the emission projections shown assume no changes in current environmental regulations.

Preliminary estimates of the emissions of pollutants that may also be important in the long range transport of pollutants, i.e. primary sulphates, volatile organics and selected metals have also been developed. Current or the most recently available emissions data for these pollutants are shown in Tables A.2.5 to A.2.8.

TABLE A.2.1

UNITED STATES

National Current and Projected SO_2 Emissions Using Combined Models (10^6 tonnes/year)[2]

	Current 1980	Projected 1990	Projected 2000
Electric Utilities	15.8	15.9	16.2
Industrial Boilers and Process Heaters	2.4[1]	3.4	6.5
Non-ferrous Smelters	1.4	0.5	0.5
Residential/Commercial	0.8	1.0	0.9
Other Industrial Processes	2.9[1]	1.2	1.5
Transportation	0.8	0.8	1.0
TOTAL U.S.	24.1	22.8	26.6

[1] In current 1980 emissions, process heaters are included with other industrial processes and not with industrial boilers.

[2] Source of Projections: These emissions estimates are based on 1980 trends using the following sources for projections for each sector: Utility-EHPA; Industrial-ICF; Res/Com-SEAS; Smelters-site by site survey; Industrial Processes-SEAS; Transportation-SEAS.

TABLE A.2.2

UNITED STATES

National Current and Projected NO_x Emissions Using Combined Models (10^6 tonnes/year)[3]

	Current 1980	Projected 1990	Projected 2000
Electric Utilities	5.6	7.2	8.7
Industrial Boilers and Process Heaters	3.5[1]	3.0	4.0
Residential/Commercial	0.7	0.7	0.6
Other Industrial Processes	0.7[1]	0.8	1.1
Transportation	8.5	7.8	9.7
Miscellaneous	0.3	-- [2]	-- [2]
TOTAL U.S.	19.3	19.5	24.1

[1] In current 1980 emissions, process heaters are included with other industrial processes and not with industrial boilers.

[2] Projections of emissions from miscellaneous sources (solid waste disposal, forest fires, etc) were not produced

[3] Source of Projections: These emissions estimates are based on 1980 trends using the following sources for projections for each sector: Utility-EHPA; Industrial-ICF; Res/Com-SEAS; Industrial Processes-SEAS; Transportation-Mobil2

TABLE A.2.3

CANADA

National Current and Projected SO_2 Emissions (10^6 tonnes/year)

	Current 1980	Projected 1990	Projected 2000
Electric Utilities	0.75	0.65	0.66
Industrial Fuel Combustion	0.62	0.33	0.23
Residential/Commercial Fuel Combustion	0.21	0.08	0.03
Non-ferrous Smelters	2.13	2.32	2.32
Other Industrial Processes[1]	0.92	1.16	1.11
Transportation	0.16	0.16	0.16
TOTAL	4.77	4.70	4.51

NOTE: Total may not add up due to rounding.

[1] Includes process emissions from petroleum refining, natural gas processing, tar sands operations, other various industrial processes.

[2] Sources of projections: The projected emission estimates are based on the current 1980 emissions and were developed by Environment Canada using energy consumption projections provided in National Energy Board reports.

TABLE A.2.4

CANADA

National Current and Projected NO_x Emissions
(10^6 tonnes/year)

	Current 1980	Projected 1990	Projected 2000
Electric Utilities	0.25	0.19	0.26
Industrial Fuel Combustion	0.30	0.30	0.33
Residential/Commercial Fuel Combustion	0.09	0.07	0.07
Non-ferrous Smelters	0.01	0.01	0.01
Other Industrial Processes[1]	0.07	0.07	0.07
Transportation	1.11	1.34	1.67
TOTAL	1.83	1.98	2.41

[1] Includes process emissions from petroleum refining, natural gas processing, tar sands operations, other industrial processes and miscellaneous sources.

[2] Source of Projections: The projected emission estimates are based on the current 1980 emissions and were developed by Environment Canada using energy consumption projections provided in National Energy Board reports.

TABLE A.2.5

National Current Emissions of Primary Sulfates (Kilotonnes)

	U.S.[1]		Canada[2]
	Total Sulfates	Acid Sulfates	Total Sulfates
Electric Utilities	255	197	15.9
Non-utility Fuel Combustion	157	108	67.8
Non-ferrous Smelters	24.6	16	33.5
Transportation	32.4	24	4.1
Other Sources	114	53	70.7
TOTAL	584	398	192.0

TABLE A.2.6

National Current Emissions of Volatile Organic Compounds (Kilotonnes)

	U.S.[1]	Canada[2]
Transportation	8 032.1	850.1
Stationary Source Fuel Combustion	1 130.0	102.1
Industrial Processes	11 090.1	413.9
Solid Waste Disposal	697.4	31.2
Miscellaneous	2 427.3	567.8
TOTAL	23 376.9	1 974.1

[1] Estimate for 1980
[2] Estimate for 1978

TABLE A.2.7

UNITED STATES

Selected Metals Emissions, By Category (tonnes)

Heavy Metals	Industrial Processes	Fuel Combustion	Trans-portation	Incineration	Misc.	TOTAL
Arsenic	4 720	540	NEG	NEG	2 830	8 090
Barium	5 315	810	NEG	NEG	2 705	8 830
Cadmium	202	455	80	48	NEG	785
Chromium	3 225	670	NEG	40	NEG	3 935
Copper	3 623	660	NEG	155	180	4 618
Lead	4 706	835	43 240	3 363	NEG	52 140
Manganese	13 737	2 575	NEG	NEG	NEG	16 312
Mercury	60	98	NEG	8	330	496
Nickel	885	8 545	810	NEG	NEG	10 240
Selenium*	122	211	NEG	NEG	NEG	333
Vanadium	245	14 235	NEG	4	NEG	14 484

* Non-metallic element

TABLE A.2.8

CANADA

Selected Metals Emissions, By Category (tonnes)

Heavy Metals	Industrial Processes	Fuel Combustion	Transportation	Incineration	Misc.	TOTAL
Arsenic	3 654	34	Neg	1	5	3 694
Barium	102	118	10	16	---	246
Cadmium	416	86	3	3	Neg	508
Chromium	69	54	12	102	7	244
Copper	2 318	91	5	79	302	2 795
Lead	4 726	30	11 658	301	60	16 775
Manganese	5 972	17	Neg	7	14	6 010
Mercury	20	9	---	2	9	40
Nickel	974	596	55	54	90	1 769
Selenium*	130	47	1	1	Neg	179
Vanadium	24	1 848	---	1	1	1 874
Antimony	52	2	3	4	---	61
Beryllium	Neg	7	---	Neg	---	7
Bismuth	61	19	Neg	2	---	82
Cobalt	78	13	1	2	1	95
Tin	43	39	Neg	85	2	169
Zinc	6 341	134	795	124	2	7 396

* Non-metallic element

A.3 FOSSIL-FUEL-FIRED ELECTRICITY GENERATION - CONTROL TECHNOLOGY SUMMARY

In this sector the focus is placed on fossil-fuel-fired electricity generation, the attendant SO_x and NO_x emissions and their control and reduction. The principal reason for this is that these facilities are important contributors to total emissions of these pollutants. While hydroelectric and nuclear facilities are commercially available forms of power production, in the past these options have been selected on the basis of the availability of natural resources, technical, social and economic considerations and not as an alternative control strategy for SO_x and NO_x emissions. Power generation processes such as magnetohydrodynamics, tidal, wind and solar power have also been excluded from consideration in this report as alternative means for SO_x and NO_x control because currently they are only emerging technologies.

SO_x Reduction

Sulfur oxide emissions can be reduced by several methods. These can be grouped generically as follows:

(1) use of naturally occurring low-sulfur fuel;
(2) removal of the sulfur before combustion;
(3) reaction of sulfur with an absorbent during combustion; and
(4) removal of the sulfur oxides after combustion.

Some processes for SO_2 control are capable of a very high removal efficiency with attendant expense; others cost much less but are limited to a relatively low level of removal efficiency.

For coal combustion, the following rankings are made for process choice at different levels of emission reduction. They are judgmental in nature, being based on a subjective evaluation of factors such as cost, commercial viability, absorption efficiency, and process reliability and may well change when site-specific considerations are taken into account. It is not considered feasible to undertake a more quantitative approach to ranking in this report.

Removal Efficiency level, %	Process Listing
Higher than 90%	1. Limestone scrubbing with additives 2. Lime scrubbing 3. Dual alkali scrubbing 4. Regenerable FGD processes
50-90% (high-sulfur coal)	1. Limestone scrubbing, (with physical coal cleaning where upper limit on SO_2 emissions applies) 2. Chemical coal cleaning[a]

Removal Efficiency level, %	Process Listing
	3. Low-sulfur fuel substitution 4. Limestone injection with a multistage burner[a]
50-90% (low-sulfur coal)	1. Lime spray dryer process 2. Limestone scrubbing
Below 50%	1. Physical coal cleaning (highly variable effectiveness due to variation in coal properties) 2. Blending with low-sulfur coal

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[a] Not presently available commercially

Tables A.3.1 and A.3.2 summarize the relative merits and available cost data for sulfur oxide controls on thermal power plants.

Physical coal cleaning costs up to around $800 per tonne of SO_2 removed for high-sulfur coals. The capital costs of wet flue gas desulfurization (FGD) at new plants range between $162-326 per kilowatt of installed capacity. Limestone systems tend to be the most economical wet FGD system. FGD processes such as the dual alkali and Wellman-Lord processes, tend to be more expensive than purely non-regenerable processes. The capital costs of dry scrubbers are $154-200 per kilowatt of installed capacity but the technology is still under development. In general, there is a wide range in the actual installed cost of FGD systems due to the variables that need to be considered on a site- specific basis.

NO_x Reduction

Several approaches can be used for NO_x control depending upon the degree of control required. Combustion modifications are the most cost-effective methods for low levels of control. Flue gas treatment by ammonia injection methods have now achieved operational acceptance on coal-fired plants in Japan and could be considered if a high degree of control is required. A rough ranking of the degree of control is as follows:

Removal efficiency level, %	Process Listing
90% or higher	1. Catalytic reduction with more than normal amount of catalyst, preceded by combustion modifications

Removal efficiency level, %	Process Listing
50-80%	1. As above, with normal amount of catalyst 2. Combustion modifications (all types) followed by non-catalytic reduction (ammonia injection without catalyst) 3. Combustion modifications alone (for lower levels of removal minimize boiler problems) 4. Low-NO_x burners
Below 30%	1. Staged combustion[a] 2. Low-NO_x burners[a] 3. Flue-gas recirculation (except for coal[a])

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[a] Used in combination with others, if necessary, to achieve the required reduction level.

The capital costs associated with combustion modification techniques for the control of NO_x emissions from thermal power plants are estimated at:

Techniques	Capital Cost	Lowest Achievable NO_x Emission Level
Low Excess Air	$0	0.9 lb per 10^6 Btu
Staged Combustion (over-fired air)	$2-3/kW	0.7 lb per 10^6 Btu
Low-NO_x Burners	$2-$10/kW	0.4-0.5 lb per 10^6 Btu

The capital cost estimates for NO_x control vary considerably due to site-specific variables (e.g., boiler type). The uncertainty in the cost data ranges from -10 percent to +30 percent. Furthermore, the cost of flue gas treatment (FGT) processes for NO_x control have not yet been determined.

TABLE A.3.1
Control Technologies for SO_2 Reduction

SYSTEM	PERFORMANCE	APPLICABILITY	UNCERTAINTY	WASTE DISPOSAL	PROBLEMS
Wet F.G.D. Limestone Lime	Acceptable Availability (90% or less)	All fuels	Cost is a function of size, sulfur content, location, redundancy of equipment, whether ash removal is included.[a]	Preferably oxidized to gypsum, otherwise settling problems in ponds and landfill unless chemically fixed.	Waste disposal because of volumes. Utilities sceptical of costs and reliability.[a]
Dual Alkali	Acceptable Availability	All fuels		As above.	As above.
Wellman Lord	Limited experience so far.	All fuels	Uncertain market by-products.	Potential water pollution problem.	High cost.
Dry Scrubber	Limited experience so far.	Low sulfur fuels	Performance data sparse.	Lime systems have minimal problems, whereas soda-based units have potential water pollution problems.	Waste disposal involves large volumes, Operational difficulties with variations in coal characteristics
Low-Sulphur Fuel		Coal	Incremental costs, availability of supplies.		Boiler derating, effects on precipitator, transportation, logistics.
Physical Coal Cleaning	Effective up to 25% sulfur removal.	Used for high pyritic sulfur coals.	Coal variability and expansion of existing facilities	Water pollution and solid waste disposal.	Energy losses, maintaining quality control.

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[a] This comment is equally applicable to all processes in this table.

TABLE A.3.2

Cost of Control Technologies for SO_2 Reduction for Representative 500 MW Coal-fired Thermal Power Plants

SO_2 CONTROL TECHNOLOGY	LOW SULFUR COAL[b]			HIGH SULFUR COAL[c]		
	CAPITAL COST $/kW	LEVELIZED COST mills/kWh	COST EFFECTIVENESS $/tonne SO_2 removed	CAPITAL COST $/kW	LEVELIZED COST mills/kWh	COST EFFECTIVENESS $/tonne SO_2 removed
Wet FGD[a]						
- Limestone	176	10.7	3806	244	16.4	840
- Lime	162	11.3	4026	224	17.4	880
- Dual Alkali	181	11.2	4004	251	17.1	880
- Wellman Lord	235	13.6	4862	326	20.9	1100
Dry FGD[a]						
- Lime	154	9.4	3344	200	17.1	880
- Sodium	158	10.2	3630	-	-	-
Physical Coal Cleaning[d]	-	-	-	-	-	790

a) The source of the costs quoted are reports EPA-600/7-81-014 and EPA-600/9-81-019a. These are hypothetical costs derived from a computer model generated by Tennessee Valley Authority, for a particular set of assumptions, viz. 500 MW unit, located in the U.S. upper mid-western states, burning coal, operating for 5500 hours per year, for 30 years. The capital and operating costs for particulate matter collection are included in the SO_2 reduction costs. It is further assumed that the capital costs are in 1982 dollars, and the revenue is in 1984 dollars. Actual historical cost data are available in EPA-600/7-81-012a Tables A1 and A2 "EPA Utility FGD Survey", Jan. 1981.

b) Low sulfur western coal, 9 700 Btu/lb. 0.7% Sulfur (dry basis); 70% SO_2 removal.

c) High sulfur eastern coal, 11 700 Btu/lb. 3.5% Sulfur (dry basis); 90% SO_2 removal for FGD processes.

d) Source: EPA-600/7-81-086; 28% SO_2 removal.

A.4 NON-FERROUS SMELTERS

In Canada there are a total of five copper smelters, three nickel-copper smelters, two lead smelters and three zinc smelters. The major sources of smelter SO_2 emissions in Canada are copper and nickel smelters located in Manitoba, Ontario and Quebec.

In the United States, there are a total of 15 copper smelters, 5 lead smelters and 5 zinc smelters. The major non-ferrous smelting capacity is located in the Western U.S. with the largest concentration in the Arizona-New Mexico area.

In 1980, SO_2 emissions from non-ferrous smelters contributed about 45% of the total in Canada and 6% in the U.S.

Off-gases from non-ferrous smelters basically fall into two categories, those with strong SO_2 strengths (defined as greater than 4% SO_2) and those of weak strengths (less than 4% SO_2). Strong gas streams can be controlled by using add-on technologies such as acid plants and liquid SO_2 plants. These processes are considered proven and, in most cases, affordable control options. While the treatment of weak gas streams constitutes a more difficult and costly problem, control options are available. These include:

(1) the use of either regenerative or non-regenerative flue gas desulfurization (FGD) processes;

(2) the modification of furnaces to produce a strong gas stream through measures such as oxygen enrichment;

(3) the replacement of sources emitting weak SO_2 streams with alternative modern technology producing strong SO_2 streams, controlled by acid plants.

FGD is practiced by a number of smelters world-wide and each system is unique to its smelter. This is a result of the particular circumstance of each application in terms of the cost for raw materials and the availability of by-product markets rather than technical suitability of the processes.

Upgrading of existing furnace operations to strengthen sulfur dioxide content can be an effective approach to SO_2 control when coupled with FGD systems. Alternative pyrometallurgical processes are of interest because they provide a strong SO_2 gas stream for control by a conventional acid plant, reduction in energy consumption, reduction in gas stream volumes, and reduction in operating costs.

Hydrometallurgical processes eliminate the generation of SO_2 streams. However they are more energy intensive and currently have limited application. A large number of alternative approaches to achieve reductions in SO_2 emissions based upon various combinations of process and control technologies are technically possible; a number of the more important ones are given in Tables A.4.1 and A.4.2. In considering any approach, it is of paramount importance to consider the unique nature of each smelter. This uniqueness factor is determined by the nature of the ore concentrates and the metallurgy required to successfully treat these concentrates. It is these aspects that govern the selection of a metallurgical process for metal winning and, in turn, the degree of sulfur containment. Each smelter requires an individual technical and economic assessment of feasibility.

TABLE A.4.1
Copper/Nickel Smelter SO_2 Control Systems

Smelter Process				SO_2 Control System							
Technology	Relative Cost[3]	Technology availability	Energy consumption[5]	Technology	SO_2 Control %	Estimated Cost[6]	Technology availability[7]	Operating reliability	Energy consumption	By-product
Green charge or multi-hearth roaster, reverb., converter	90-110	High	High 106-118	Acid plant on converter	To 50%	52	High[4]	High	Low	Sulfuric acid
Fluid-bed roaster, reverb., converter (base case)	100	High	High 100	Acid plant on roaster	To 45%	33	High	High	Low	Sulfuric acid
Multi-hearth roaster, reverb., converter	110	High	High 100	Non-regenerative FGD	To 85%	134	Low	Low	High	Sulfur compound for waste disposal
Multi-hearth roaster, reverb., converter	110	High	High 100	Regenerative FGD	To 85%	108	Low	Low	High	Sulfuric acid
Fluid-bed roaster, electric furnace, converter	100	High	Very High 106-156	Acid plant on roaster, electric furnace, converter	To 90%	33	High[4]	High	Low-Med.	Sulfuric acid
Fluid-bed roaster, reverb., converter	100	High	High 100	Acid plant on roaster and non-regenerative FGD on weak gas streams	90-92%	83	Low	Low	High	Sulfuric acid and sulfur compound for waste disposal
Fluid-bed roaster, reverb., converter	100	High	High 100	Acid plant on roaster and regenerative FGD on weak gas streams and acid plant	90-92%	70	Low	Low	High	Sulfuric acid
Dryer, oxygen-enrishec reverb., converter	90	Med.	Med. 90-95	Acid plant	90-94%	52	High[4]	High	Low-Med.	Sulfuric acid

TABLE A.4.1 (continued)
Copper/Nickel Smelter SO_2 Control Systems

	Smelter Process			SO_2 Control System						
Technology	Relative Cost[3]	Technology availability	Energy consumption[5]	Technology	SO_2 Control %	Estimated Cost[6]	Technology availability[7]	Operating reliability	Energy consumption	By-product
Fluid-bed roaster electric furnace converter	100	High	Very High 106-156	Acid plant on roaster, electric furnace, converter plus FGD system on weak gas streams	To 95%	44	Med.	Med.	Med.	Sulfuric acid and sulfur compound for waste disposal
Direct furnace smelting, converter (Inco, Outokumpu, Noranda)	80	High	Low 60-80	Acid plant on flash furnace and converter	94-95%	40	High	High[4]	Low	Sulfuric acid
Direct frunace smelting, converter (Inco, Outokumpu, Noranda)	80	High	Low 60-80	Acid plant on flash furnace plus FGD system on weak gas streams	To 95%	43	Med.	Med.	Med.	Sulfuric acid and sulfur combound for waste disposal
Continuous smelting (Mitsubishi, Noranda)	135	Med.[1]	Low 60-80	Acid plant	98-99%	33	High	High	Low	Sulfuric acid
Hydrometallurgy	135	Low[2]	High to Very High 100-200	?	To 99.5%	?	?	?	?	Elemental sulfur

[1] Can be used for clean copper concentrates

[2] Problems with precious metals recovery, limited operating experience; could be considered for some special cases

[3] Capital cost relative to a base case facility of calcine fed reverberatory furnace

[4] Capture of off-gases from nickel converters and electric furnaces not yet developed

[5] Smelter energy consumption is relative to base case of calcine fed reverberatory furnace taken as 100%

[6] Estimated cost per tonne of SO_2 removed in 1980 U.S.$

[7] High means technology is used at a number of smelters; medium means technology is used at a few smelters; low means technology is used at only one smelter or is being evaluated at a pilot scale facility

Source: Section C.2. References 1, 3, 4, 15

TABLE A.4.2
Comparison of Cost of Abating SO_2 by Various Options(1)

Control Options	Off-gas			Capital Cost	Operating Cost	Amortization	Total Annual Cost	Cost Per tonne SO_2 removed $ (2)
	SCFM	% SO_2	SO_2 tonnes per day	10^6 $	10^6 $	10^6 $	10^6 $	
Single contact acid plant on strong gas stream(3)								
- continuous gas only	27 000	12	346	17	1.5	2.5	4.0	33
- variable gas only	49 000	5-8	346	28	2.2	4.1	6.3	52
- continous gas & variable gas	36 000	6-12	346	22	1.8	3.1	4.9	40
Non-regenerative scrubbing of weak gas stream(4)								
- lime	400 000	1	430	40	17.4	5.7	23.1	154
- limestone	400 000	1	430	47	13.4	6.8	20.2	134
Regenerative scrubbing of weak gas stream(4)								
- MgO and acid plant	400 000	1	430	65	10.9	9.3	20.2	134
- Citrate and acid plant	400 000	1	430	58	7.9	8.3	16.2	108
Replacement of process producing weak gas stream with modern process(5)								
- existing old smelter process (uncontrolled)				--	26.0(6)	---	26.0	---
- modern process	63 000	8	540	215	22.0(6)	30.9	52.9	115(7)

1. All costs are in 1981 U.S. dollars. Capital costs is amortized over 12.5 years at 10% interest.
2. Production is based on 350 operating days per year and assuming 100% control of SO_2.
3. Figures are derived from "A Study of Sulfur Containment Technology in the Non-ferrous Metallurgical Industry", Economic and Technical Review Report EPS-3-AP-79-8, Air Pollution Control Directorate, Environment Canada, April 1980.
4. Non-regenerative and regenerative scrubbing of weak gas cost estimates are taken from the EPA data presented in the Appendices. The cost estimates for the regenerative scrubbing of weak gas stream also include a capital cost of $20 million and an annual operating cost of $6.8 million for a 660 tonnes per day sulfuric acid plant.
5. The cost estimates are for a copper smelter producing 100 000 tonnes per annum of copper. Modern processes are processes such as the INCO, Noranda and Mitsubishi processes.
6. The annual operating cost of a fully depreciated, existing reverb based smelter with no SO_2 controls is estimated to be about $26 million. The operating cost of the modern processes is approximated at $22 million.
7. The difference between the annual operating cost for the facility and the old facility are allocated to SO_2 control. The cost per tonne SO_2 fixed is computed assuming 100% SO_2 capture.

A.5 MOBILE SOURCES SUMMARY

The mobile sources sector is a major source of NO_x emissions (currently 44% of NO_x in the U.S. and 60% in Canada) but SO_x emissions from this sector are negligible. Control technology is available for NO_x and stringent emission limits for the design performance of new vehicles are in place in the U.S. and are being considered in Canada for 1985.

The technology for meeting the current automobile emission standards in the U.S. employs the "three-way" catalyst technology (called three-way because it controls HC, CO and NO_x), coupled with a series of electronic and vacuum sensing devices which detect and control selected engine operating parameters.

Between 1980 and 2000, NO_x emissions from this sector are projected to increase by about 15% in the U.S. and by 50% in Canada. For practical purposes this disparity is accounted for by differences in the light duty, gasoline powered vehicles partly because more stringent emission standards were introduced in 1981 in the U.S. and partly because a much faster growth rate for vehicle miles travelled (VMT) by light duty vehicles is being projected in Canada.

In the absence of changes to federal emission limits in either country, the contribution of the transportation sector to NO_x emissions in the year 2000 is projected to be 40% in the U.S. and 70% in Canada. The opposite trends in the two countries (see 1980 percentages above) is explained primarily by the factors cited above but also by the opposite directions of the trend in electric utility emissions (29% to 36% in the U.S. and 13% to 10% in Canada) and the less stringent emission standards for light duty vehicles in Canada.

A.6 INDUSTRIAL, COMMERCIAL, AND RESIDENTIAL FUEL COMBUSTION

Industrial, commercial and residential fuel combustion accounts for approximately 14 percent of combined U.S.-Canada SO_2 emissions and approximately 20 percent of their combined NO_x emissions. This sector is characterized by a wide diversity in boiler sizes (i.e., from 10^5 Btu/hr to greater than 250 x 10^6 Btu/hr), combustion systems, and fuel characteristics. In addition, the technical expertise of the owner/operator varies from the homeowner to the skilled technician. Industrial boilers are the major emitters in this sector.

There are various control options that can be considered to reduce sulfur dioxide emissions from this sector. These are:

(1) replace sulfur containing fuels such as coal and petroleum with natural gas or electrical energy, or substitute lower sulfur fuel of the same type;

(2) desulfurize fuels such as heating oils and heavy fuel oils;

(3) use flue-gas desulfurization techniques to remove sulfur dioxide from combustion flue gases.

FGD can lower sulfur oxide emissions by up to 90 percent. Fluid-bed combustion can achieve a 70-85 percent SO_2 reduction at costs which are estimated to be competitive with FGD. The dual-alkali FGD process is the dominant sulfur oxide control technology for industrial boilers. Sodium-based once-through systems are used in industries which produce a sodium-containing waste stream such as pulp and paper and textile mills (from de-ionizer recharging). There are two installations of the lime-spray-dryer SO_2 control process on commercial boilers in the United Sates.

As in utility boilers, combustion modification is the principal method of controlling NO_x emissions. In California, several thermal-NO_x (non-catalytic NO_x control) installations have been purchased; however, none is in commercial operation at this time. The NO_x emission limits that are achievable using combustion modification are dependent upon the fuel type (oil, coal, gas) and firing method (for coal, pulverized coal, chain-grate stoker, vibrating-grate stoker, and spreader stoker).

The cost of SO_2 control technology varies as a function of boiler size, load factor, and fuel sulfur content. Thus the uncertainty in capital and annual costs can be large. The capital costs and operating costs shown in Figures A.6.1 and A.6.2 can be in error by as much as $\underline{+}40$ percent. The cost of retrofitting industrial boilers is highly uncertain since space limitations and other restrictions can cause significant variations.

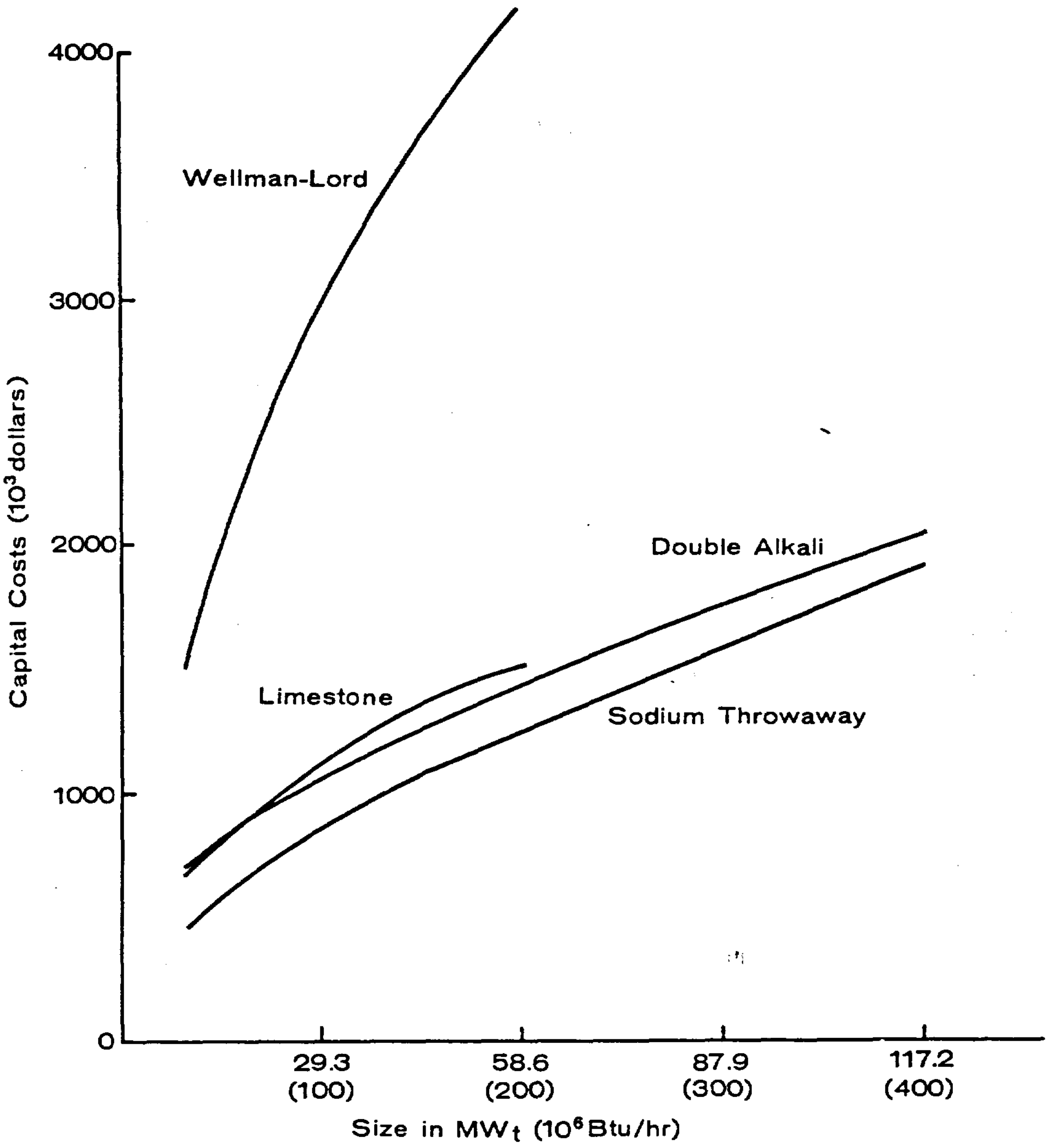

FIGURE A.6.1 FGD CAPITAL COSTS VERSUS UNIT SIZE
(3.5% S coal, 90% removal)

Source: Technical Assessment Report for Industrial Boiler Applications:
Flue Gas Desulfurization
Industrial Environmental Laboratory; USA E.P.A.
November 1979

Note: Costs are given in U.S. $ (1978).

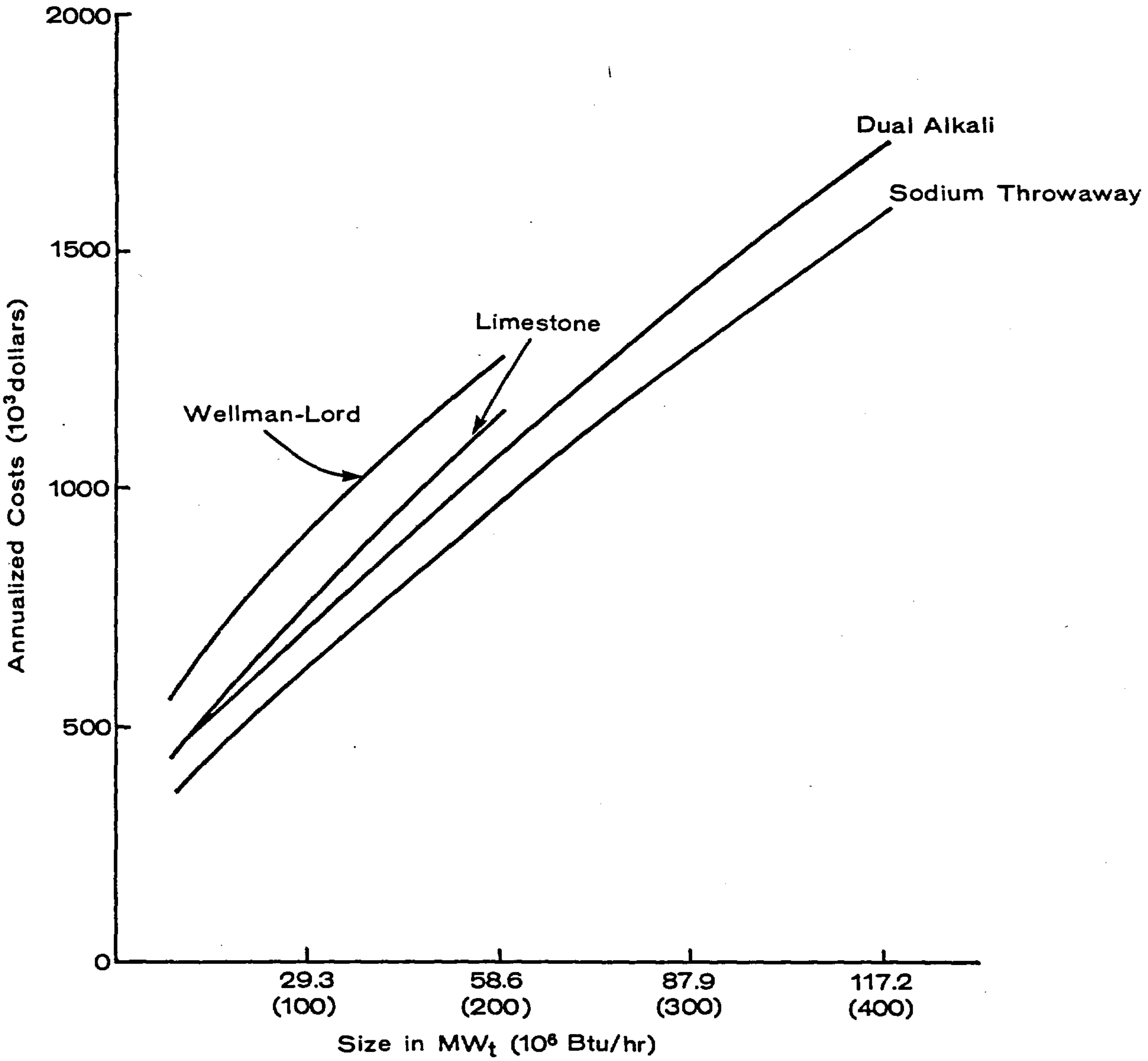

FIGURE A.6.2 FGD ANNUALIZED COSTS VERSUS UNIT SIZE
(3.5% S coal, 90% removal)

Source: Technical Assessment Report for Industrial Boiler Applications:
Flue Gas Desulfurization
Industrial Environmental Laboratory; USA E.P.A.
November 1979

Note: Costs are given in U.S. $ (1978).

NO_x control technology for commercial and residential boilers has not progressed as rapidly as for the larger boilers, primarily because of the considerably smaller emission reduction potential for this sector. However, results of research indicate that some emission reduction is economically possible for commercial and residential boilers. Precise cost figures for these boilers are not available, but preliminary indications are that any increase in cost will be largely offset by the fuel savings and increased thermal efficiency.

A.7 RESEARCH AND DEVELOPMENT SUMMARY

The principal research and development activities currently underway are directed toward the control of sulfur dioxide and nitrogen oxides from fuel combustion processes. They can be grouped into three main areas; SO_2 control, NO_x control and combined SO_x/NO_x control.

With respect to SO_2 control, both wet and dry flue gas desulfurization technologies are being examined with a view to enhanced removal efficiencies. As well, studies are underway to assess state-of-the-art and advanced coal cleaning methodologies as techniques for meeting SO_2 emission regulations.

NO_x controls are being examined from the perspective of combustion modification techniques for a number of different fuel types.

Combined SO_2/NO_x controls are being assessed by the development and evaluation of limestone injection multistage burners (LIMB) and fluid bed combustion.

Recommendations are made in this report regarding other R & D initiatives that could be undertaken. These include further work on SO_2 and NO_x reduction for fossil-fuel-fired electrical generation processes and industrial boilers, process and control technology development projects for the control of SO_2 emissions from non-ferrous smelters and projects to improve emissions inventories.

B. TRENDS IN EMISSIONS: SO_2 AND NO_x

B.1 HISTORICAL EMISSION TRENDS

Introduction

The primary objective in developing historical emission trends is to recreate the emission situation of several decades ago, so that such data can be used in atmospheric models to provide an insight into sulfur deposition rates for those periods. These rates can then be compared to current deposition rates for an indication of the rate of change of the environment with time.

Factors other than strict fluctuations in the magnitude of acid precipitation precursor emissions, however, have also played a role in changes in deposition rates with time and these should not be overlooked. For example, concurrent with increases in SO_2 and NO_x emissions over the past 40 years has been a substantial increase (by a factor of five) in the stack height for utility sources. Also, SO_2 emissions from coal burning have changed in most regions from a wintertime peak to a summertime peak in emission rate. The importance of such factors has not been well determined at this time.

United States

Historically, data records on emissions and emission rates have been maintained only since the early 1970's. Consequently, in order to recreate such emissions, it is necessary to use other information. One of the most accepted approaches to retrospectively calculating emissions is to employ emission factors with industrial production and fuel use data. Records on these data are available and provide an indication of historical industrial production levels and how various fuels have been consumed by different sources. Knowing the emission rates of various sources, the sulfur content of the fuel, and the type of emission controls on a particular source, it is possible to estimate the emissions of various source categories.

<u>Data Uncertainty</u>: It is extremely difficult to provide an accurate estimate of the data uncertainty in making the above calculations. Generally, it is felt that the emission estimates for the utility sector are probably within 25% accuracy for the post-1965 years; however, no accuracy figures are available for the pre-1965 estimates.

No attempt has been made to assess the accuracy of the calculations for other sources, except to examine the general trends exhibited to determine areas where the trends are well outside of what might be expected. Appendix 3 describes a methodology developed to estimate probable errors in current emissions. Errors in historical data would be expected to be significantly greater than in current emission estimates, due to the necessity of estimating many more emission related parameters such as fuel sulfur contents and pollution control efficiencies, than is necessary for recent years. Also, for years prior to 1950 the availability of suitable published data on fuel consumption and industrial production becomes very limited.

National Trends in Emissions: Table B.1.1 provides a summary of the emissions of various air pollutants from 1940 through 1980. These estimates are calculated using internally consistent data sources and calculation procedures, to the maximum possible extent. Because these procedures are necessarily less detailed than the procedures used to calculate current emissions estimates for 1980, the historical emissions are not totally consistent with the current emissions estimates presented elsewhere in this report. As a result, the historical estimates of emissions should be viewed only as an internally consistent set of data showing trends, and should not be compared with other emissions estimates. Additional information on the total national emissions along with an expanded explanation of the procedures for calculating these estimates is given in National Air Pollutant Emissions Estimates, 1940-1980 (EPA-450/4-82-001) available from the National Air Data Branch, OAQPS, EPA at Research Triangle Park, NC.

TABLE B.1.1

Summary of National Emission Estimates

Units of Measurement	Year	Particulate Matter (PM)	Sulfur Oxides (SO_x)	Nitrogen Oxides (NO_x)	Volatile Organics (VOC)	Carbon Monoxide (CO)
Teragrams/Year (10^6 metric tonnes/year)	1940	21.9	17.4	6.5	13.9	74.7
	1950	23.2	19.6	9.3	17.5	82.8
	1960	20.2	19.2	12.7	21.6	90.8
	1970	17.6	27.9	18.5	27.1	110.9
	1971	16.4	26.5	19.0	26.4	110.5
	1972	14.9	27.3	20.1	26.7	109.7
	1973	13.9	28.4	20.4	26.2	107.4
	1974	12.1	27.0	20.1	23.8	102.5
	1975	10.1	25.6	19.6	22.8	98.1
	1976	9.4	26.4	20.9	23.7	100.4
	1977	8.5	26.4	21.3	23.8	97.8
	1978	8.6	24.8	21.5	24.4	96.7
	1979	8.5	25.3	21.5	23.4	92.6
	1980	7.8	23.7	20.7	21.8	85.4
10^6 short tons/year	1940	24.1	19.2	7.2	15.3	82.3
	1950	25.6	21.6	10.3	19.3	91.3
	1960	22.3	21.2	14.0	23.8	100.1
	1970	19.4	30.8	20.4	29.9	122.2
	1971	18.1	29.2	20.9	29.1	121.8
	1972	16.4	30.1	22.2	29.4	120.9
	1973	15.3	31.3	22.5	28.9	118.4
	1974	13.3	29.8	22.2	26.2	113.0
	1975	11.1	28.2	21.6	25.1	108.1
	1976	10.4	29.1	23.0	26.1	110.7
	1977	9.4	29.1	23.5	26.2	107.8
	1978	9.5	27.3	23.7	26.9	106.6
	1979	9.4	27.9	23.7	25.8	102.1
	1980	8.6	26.1	22.8	24.0	94.1
Change 1940-1980		-64%	+36%	+218%	+57%	+14%
Change 1970-1980		-56%	-15%	+12%	-20%	-23%

Historical Emission Trends on Regional Scale: To examine emission trends on a regional basis in the United States, a data file has been constructed which also uses historical fuel use figures to calculate emissions of SO_2 and NO_x from various categories of sources. The basic file contains emissions at the individual state level for the following source categories:

- Electric Utilities
- Industrial
- Commercial/Residential
- Pipelines
- Highway Vehicles
  - Gasoline-Powered
  - Diesel-Powered
- Miscellaneous
- Railroads
- Vessels
- Misc. Off-Highway Mobile
- Chemicals
- Primary Metals
- Mineral Products
- Petroleum Refineries
- Others

The current file contains data for 33 eastern states plus the District of Columbia. Years on record for the file are 1950, 1960, 1965, 1970, 1975, and 1978. (Reference: Pacific Environmental Services, Inc.)

For the electric utility sector, all power plants greater than 25 megawatts have been identified and located in the appropriate county within each state for each year of record. Emissions of SO_2 and NO_x have been determined for each year for all such power plants. Consequently, it is possible to identify power plant emissions on a county-by-county level for each year of record for all 33 states. The file identifies each power plant by name, size, county location, and SO_2 and NO_x emissions from coal, oil, and natural gas consumption. The file also contains fuel use information and has some limited data on stack height.

To distribute the non-power plant emissions to a county level, work is underway using historical census data to assign the statewide emissions to the county level. The technique to be used is to apportion the emissions to the county base on a historical population basis.

As an example of the information from this file, a sample state and county are outlined in Table B.1.2:

TABLE B.1.2

SO_x Emissions (x 10^3 tons)

STATE OF KENTUCKY	1950	1955	1960	1965	1970	1975	1978
Non-PP	34.5	153.6	262.3	310.7	198.4	117.7	108.8
Power Plant	28.6	251.2	368.8	603.3	1082.5	1349.1	1221.1
TOTAL	63.1	404.8	631.1	914.0	1280.9	1466.8	1330.0
County of Jefferson, Ky							
Power Plant							
Canal	1.9	1.5	-	-	-	-	-
Cane Run	-	3.0	11.4	17.0	27.1	22.4	19.1
Mill Creek	-	-	-	-	-	17.8	21.0
Paddy's Run	7.4	10.4	9.4	4.1	3.5	0.7	2.3
Waterside	0.9	0.8	-	-	-	-	-
TOTAL PP	10.2	15.7	20.8	21.1	30.6	40.9	42.4

Non-Power Plant - Jefferson County, Ky
Information not on file

To assist in examining the historical emission trends on a regional scale, tables have been prepared in which the states are grouped according to the appropriate EPA regional offices (Regions I through V). Trends in SO_x and NO_x emissions for each state along with a summary for each grouping of the states (by regional office) are shown in the following tables (Tables B.1.3 and B.1.4). To some extent, the regional office grouping can be used to examine trends in the following broad geographical areas of the country:

Regions I and II - Northeast
Region III - Mid-Atlantic
Region IV - Southeast
Region V - Midwest

In the northeast, SO_x emissions appear to have decreased by about 40% from 1955 to 1978. While the trend may be real, it should be noted that the data for 1950 and 1955 are less reliable than for the more recent years. Part of this apparent decrease may be due to errors in the data; however, it should be noted that a 38% reduction in SO_x emissions in the northeast also was observed between 1965 and 1978. Therefore, SO_x emissions appear to have been significantly reduced in the northeast since 1950.

Contrary to the reduction in SO_x emissions noted in the northeast, the states in Region III (mid-Atlantic) have generally maintained about the same level of SO_x emissions. There appears to have been a small steady increase between 1955 and 1970, and a small but steady decline between 1970 and 1978.

The southeastern states exhibited a sharp increase in SO_x emissions between 1950 and 1978 with the data suggesting that this increase may have been as high as three to five-fold.

In the midwest (Region V), there appears to have been a significant steady increase in SO_x emissions between 1955 and 1965 and a steady decline in these emissions since 1965. Levels today are about 25% higher than in 1955 in this area of the country.

The states of Arkansas, Iowa, Louisiana, Missouri, and Texas have exhibited a steady increase in SO_2 emissions since 1950. NO_x emissions in Arkansas and Iowa appear to have doubled since 1955, while Louisiana and Missouri appear to have experienced a greater than 50% increase and Texas about 24%.

All the areas examined exhibit significant increases in NO_x emissions over the time period studied. This increase ranges from about a factor of two in the northeast to over three in the south. The trends also indicate that NO_x emissions have increased steadily and did not peak in the mid-1960's as did SO_2 emissions.

TABLE B.1.3

Historical Trends in SO_2 Emissions

	x 10^3 tons						
State	1950	1955	1960	1965	1970	1975	1978
			EPA - REGION I				
Conn.	130.3	139.1	241.6	457.6	317.3	191.0	112
Maine	37.8	45.6	70.2	97.0	82.0	67.8	66
Mass.	906.9	956.7	374.6	443.2	584.4	362.2	402.2
New Hamp.	73.3	89.7	29.1	41.2	95.9	75.4	67.8
Rhode Island	67.7	80.2	87.3	41.2	60.1	24.3	19.7
TOTAL	1 215.5	1 311.3	802.8	1 080.2	1 139.1	720.7	667.7
			EPA - REGION II				
New York	847.0	1 126.0	1 427.4	1 645.4	1 455.0	1 079.0	1 041.1
New Jersey	*1 308.8	*1 486.2	482.6	623.4	590.2	341.0	323.7
TOTAL	*2 155.8	*2 612.20	1 910.0	2 268.8	2 045.2	1 420.0	1 364.8
			EPA - REGION III				
Delaware	105.4	136.0	196.1	217.8	223.4	193.6	188.2
D.C.	32.4	31.0	38.5	47.9	78.0	27.1	17.6
Maryland	398.9	515.5	518.2	588.1	467.7	322.3	357.3
Penn.	* 970.2	2 138.4	2 362.2	2 546.8	2 245.7	2 130.8	1 900.0
Virginia	157.2	277.4	171.4	188.1	475.2	381.0	359.9
West Va.	243.5	617.8	529.7	776.8	979.7	1 220.0	1 049.5
TOTAL	*1 907.6	3 716.1	3 816.1	4 365.5	4 469.7	4 274.8	3 872.6
			EPA - REGION IV				
Alabama	139.5	522.7	613.5	892.3	979.1	986.5	762.1
Florida	225.5	350.5	341.1	501.6	862.3	827.9	685.9
Georgia	119.9	163.6	198.2	303.0	410.4	571.4	707.0
Mississippi	46.9	43.3	41.1	44.6	79.4	193.0	264.3
Kentucky	113.1	404.8	631.1	914.0	1 280.9	1 466.8	1 330.0
North Carolina	306.1	347.4	232.4	294.4	533.2	500.5	562.3
South Carolina	44.5	84.3	115.9	121.7	185.4	202.3	288.6
Tennessee	97.3	369.2	731.2	771.5	988.1	1 141.9	1 162.8
TOTAL	1 092.8	2 285.8	2 904.5	3 843.1	5 318.8	5 890.3	5 763.0

TABLE B.1.3 (continued)

Historical Trends in SO_2 Emissions

			x 10^3 tons				
State	1950	1955	1960	1965	1970	1975	1978
			EPA - REGION V				
Illinois	* 869.8	2 172.1	2 452.9	2 791.4	2 506.5	1 950.6	1 747.2
Indiana	533.1	1 174.2	1 840.8	2 180.3	1 941.5	1 980.0	1 848.2
Mich.	519.2	702.7	1 085.5	1 521.7	1 520.9	1 450.6	1 117.8
Minn.	504.5	536.4	391.8	419.8	450.7	382.3	379.0
Ohio	* 885.0	2 344.9	2 933.2	3 181.2	3 125.2	3 271.2	3 115.3
Wisc.	217.2	304.2	604.0	703.8	322.3	* 166.6	663.6
TOTAL	*3 528.8	7 234.5	9 308.2	10 798.2	9 867.1	9 201.3	8 871.1
			OTHER STATES				
Arkansas	41.0	36.7	26.1	29.9	37.0	68.6	121.6
Iowa	173.2	258.0	364.5	440.8	370.2	314.0	385.0
Louisiana	233.0	261.2	219.4	268.7	318.0	295.1	359.0
Missouri	715.7	*2 155.1	582.6	674.9	1 107.3	1 174.3	1 307.7
Texas	1 011.7	1 073.8	900.0	1 074.3	1 136.8	1 123.8	1 244.8

* Questionable data

Source: Pacific Environmental Services, Inc.

TABLE B.1.4

Historical Trends in NO_x Emissions

			x 10^3 tons				
State	1950	1955	1960	1965	1970	1975	1978
EPA - REGION I							
Conn.	85.7	100.0	152.6	169.0	202.0	182.0	183.0
Maine	44.6	46.7	49.1	60.2	75.8	72.7	76.7
Mass.	164.2	195.0	254.9	303.4	359.9	340.2	364.3
New Hamp.	18.2	22.6	31.1	39.7	63.7	67.5	66.9
Rhode Island	33.5	32.9	45.2	36.4	55.2	44.9	42.4
TOTAL	346.2	397.2	532.9	608.7	756.6	707.3	733.3
EPA - REGION II							
New York	493.6	606.5	767.0	919.1	1 000.3	869.3	908.9
New Jersey	281.5	319.1	362.7	439.1	538.3	462.0	494.4
TOTAL	775.1	925.6	1 129.7	1 358.2	1 538.2	1 331.3	1 403.3
EPA - REGION III							
Delaware	19.8	30.1	51.2	61.1	71.9	65.2	70.6
D.C.	30.8	34.3	35.0	38.1	58.3*	36.5	33.5
Maryland	108.9	138.5	222.9	292.5	298.8	294.9	313.9
Penn.	479.1	693.2	1 020.2	1 143.1	1 089.2	1 093.1	1 120.7
Va.	183.8	228.0	259.9	361.8	433.5	420.8	435.2
West Va.	118.9	217.4	225.0	322.3	346.9	470.8	462.4
TOTAL	941.3	1 341.5	1 814.2	2 218.9	2 298.6	2 381.3	2 436.3
EPA - REGION IV							
Alabama	172.6	367.0	308.6	448.3	416.1	580.8	473.0
Florida	206.8	263.4	321.5	420.8	552.1	733.2	777.4
Georgia	170.8	198.9	226.9	296.7	398.1	520.5	548.8
Kentucky	145.4	208.0	279.1	377.6	497.2	567.3	563.0
Mississippi	97.1	80.8	151.2	196.4	304.5	243.5	272.8
N.C.	192.0	210.7	290.0	376.2	546.4	568.0	591.0
S.C.	87.4	125.4	150.2	178.2	237.3	253.7	300.2
Tenn.	164.9	232.7	335.9	380.3	467.1	615.5	592.9
TOTAL	1 237.0	1 686.9	2 063.5	2 674.5	3 418.8	4 082.5	4 119.1

TABLE B.1.4 (continued)

Historical Trends in NO_x Emissions

State	1950	1955	1960	1965	1970	1975	1978
			x 10^3 tons				
			EPA - REGION V				
Illinois	600.1	890.4	895.9	1 063.7	1 119.8	1 129.1	1 129.9
Indiana	296.6	447.2	584.9	555.2	576.4	631.7	600.6
Mich.	318.3	382.9	587.3	746.4	846.6	840.7	841.1
Minn.	164.7	187.6	240.1	275.5	331.3	370.0	399.6
Ohio	498.2	771.5	960.5	1 088.3	1 165.1	1 221.0	1 277.1
Wisc.	196.5	215.4	296.6	367.4	455.0	455.7	473.2
TOTAL	2 074.4	2 895.0	3 565.3	4 090.5	4 494.2	4 638.2	4 723.5
			OTHER STATES				
Arkansas	112.6	122.9	115.9	147.6	193.2	171.4	217.9
Iowa	167.2	203.6	216.4	248.1	309.6	308.8	321.0
Louisiana	283.5	330.2	535.8	760.1	1 016.9	1 072.0	1 593.7
Missouri	198.1	251.0	294.6	339.1	424.6	593.6	563.0
Texas	876.5	933.1	1 658.0	2 044.6	2 551.3	2 833.9	3 309.5

*Questionable data

Canada

Historical emissions data have been developed for sulfur dioxide and nitrogen oxides for the years 1955 and 1965. Information regarding production and fuel consumption was obtained from various federal government departments. Other data were obtained from internal files and other available sources (1). Generally, emission factors (either Canadian or U.S. adapted to Canadian conditions) were applied to the basic data, except from copper-nickel smelters and some power plants, for which actual emission data were obtained (2,3).

Emissions data on 1976 have been taken from the document "A Nationwide Inventory of Emissions of Air Contaminants" (4). This report is published biennially to estimate emissions from 70 various sectors.

Total Canadian emissions of SO_2 and NO_x for each of the years 1955, 1965 and 1976 are given in Table B.1.5. Table B.1.6 presents this information for eastern Canada (i.e.-Manitoba and east). Total SO_2 emissions in Canada for 1976 were approximately 5.3 million tonnes, 6.6 million tonnes in 1965 and 4.5 million tonnes in 1955. The major changes in emissions were due to the copper-nickel smelting industry which contributed 64%, 59% and 49% of total SO_2 emissions in the years 1955, 1965 and 1976 respectively. Since all copper-nickel smelters are in eastern Canada, the contribution of smelter emissions to total emissions are 67%, 70%, and 59% for 1955, 1965 and 1976 respectively.

Sulfur dioxide emissions from power plants were 0.05 million tonnes in 1955, before increasing to 0.25 million tonnes in 1965 and 0.55 million tonnes in 1976. Over 90% of the total was emitted in eastern Canada for each year considered.

Sulfur dioxide emissions from non-utility fuel combustion decreased slightly from 1955 to 1965 (from 1.2 to 1.1 million tonnes). A significant decrease occurred as a result of fuel switching from coal to oil, but increased as a result of high fuel combustion emissions in the petroleum refining sector. In 1976, emissions were slightly lower at 0.9 million tonnes. The decrease between 1965 and 1976 was mainly due to the control of emissions at petroleum refineries. Industrial fuel combustion contributed 72% of total non-utility combustion emissions in 1976, compared to 92% and 82% in 1955 and 1965, respectively. Emissions from transportation sources decreased between 1955 and 1965, largely due to the reduction in coal consumption by railroads, and then increased in 1976 again to the 1955 level, mainly due to the larger number of vehicles on the road.

Iron ore processing emissions of sulphur dioxide increased by approximately 75% between 1955 and 1976 (from 0.1 million tonnes to almost 0.2 million tonnes). Other industrial processes, classified as "others" in the tables, had significantly higher SO_2 emissions in 1965 (1.1 million tonnes) compared to

1955 (0.2 million tonnes). This increase was mainly due to increased industrial activity, especially with respect to natural gas processing and petroleum refining. Levels in 1976 were 1.0 million tonnes. Eastern Canadian provinces contributed 66%, 23% and 22% of total "other" emissions in 1955, 1965 and 1976 respectively. Increased production at natural gas plants was the main reason for higher western SO_2 emissions.

Total NO_x emissions for Canada increased significantly, from 0.6 million tonnes in 1955 to 1.9 million tonnes in 1976. This increase was due mainly to significant changes in the transportation sector and power plants. Gasoline-powered motor vehicles, which contributed 0.17 million tonnes of NO_x emissions in 1955, reached a level of 0.5 million tonnes in 1976. Diesel-powered engines were the other major source of NO_x emissions in the transportation sector, increasing by a factor of 5 since 1955. Demand for electricity, resulting in the growth of the thermal power generating industry, caused NO_x emissions to reach a level of 0.2 million tonnes in 1976, compared to 0.01 million tonnes in 1955.

Eastern Canada contributed 71%, 66% and 61% of total NO_x emissions in 1955, 1965 and 1976 respectively. This occurred as a result of the shift in industrial activity and population to the west.

REFERENCES

1. Environment Canada, Air Pollution Control Directorate, Data Analysis Division (Unpublished Information)(December 1980).

2. Environment Canada, Air Pollution Control Directorate, Copper-Nickel Smelter Complexes in Canada, SO_2 Emissions (1950-2000), Report EPS-3-AP-80-5 (January 1981).

3. EPS Publication AP-42, "Compilation of Air Pollutant Emision Factors", third edition, August 1977.

4. Environment Canada, Air Pollution Control Directorate, A Nationwide Inventory of Emissions of Air Contaminants (1976), Report EPS-3-AP-80-1 (January 1981).

TABLE B.1.5

Historical Emissions of SO_2 and NO_x - Canada (Tonnes per year)

SECTOR	1955		1965		1976	
	SO_2	NO_x(1)	SO_2	NO_x(1)	SO_2	NO_x(1)
Cu-Ni Smelters*	2 887 420	-------	3 901 950	-------	2 604 637	-------
Power Plants	56 246	10 335	261 837	57 402	614 323	206 454
Other Combustion**	1 210 108	227 837	1 129 548	247 323	884 867	445 315
Transportation	83 474	323 785	48 669	511 868	77 793	1 017 936
Iron Ore Processing	109 732	-------	155 832	-------	175 829	-------
Others	189 876	68 065	1 095 341	33 778	954 215	190 327
TOTAL	4 536 856	630 022	6 593 177	850 371	5 311 664	1 860 032

* Includes emissions from pyrrhotite roasting operations.

** Includes residential, commercial, industrial and fuel wood combustion. Industrial fuel combustion also includes fuel combustion emissions from petroleum refining and natural gas processing.

(1) NO_x expressed as NO_2

TABLE B.1.6

Historical Emissions of SO_2 and NO_x - Eastern Canada (Tonnes per year)

SECTOR	1955		1965		1976	
	SO_2	NO_x(1)	SO_2	NO_x(1)	SO_2	NO_x(1)
Cu-Ni Smelters*	2 887 420	-------	3 901 950	-------	2 604 637	-------
Power Plants	52 174	7 295	254 857	45 797	554 417	142 470
Other Combustion**	1 067 509	183 556	990 537	159 870	792 227	252 316
Transportation	50 970	207 762	34 416	336 471	52 827	652 737
Iron Ore Processing	109 732	-------	155 832	-------	175 829	-------
Others	125 589	48 171	255 011	14 940	207 955	94 763
TOTAL	4 293 394	446 784	5 592 603	557 078	4 387 892	1 142 286

* Includes emissions from pyrrhotite roasting operations.

** Includes residential, commercial, industrial and fuel wood combustion. Industrial fuel combustion also includes fuel combustion emissions from petroleum refining and natural gas processing.

(1) NO_x expressed as NO_2

B.2 PRESENT EMISSIONS

B.2.1 United States

Estimated emissions of SO_2 and NO_x for calendar year 1980 are presented here. These estimates rely upon source inventories such as the National Emissions Data System (NEDS), published references for quantities and characteristics of fuels consumed, additional published references for industrial production data, and air pollutant emission factors, such as those available from Compilation of Air Pollutant Emission Factors, EPA publication AP-42. All of these sources of information were used to produce an overall emissions inventory that represents the best practical available emissions estimates. The emission inventory methodology is described in additional detail in Appendix 2.

Estimated emissions by State for major source categories are presented in Tables B.2.1, B.2.2 and B.2.3. These emissions estimates can be further disaggregated into more detailed source categories than shown here. For the sake of brevity, more detailed data are not included in this report. The estimated emissions for 1980 were derived through a more refined methodology than that used to estimate historical trends in emissions. As a result the estimated historical emissions are not totally consistent with the 1980 emissions estimates. The 1980 emissions estimates were all calculated on an annual calendar year basis. Temporal refinement of the data to provide seasonal or monthly emissions estimates was not completed during Phase III.

Emissions estimates for electric utilities were derived largely from available data for individual facilities. These data were compiled from U.S. Department of Energy data files by E.H. Pechan and Associates, Inc. These results were cross-checked with individual facility data in NEDS. For SO_2, NEDS emissions estimates have been adjusted, if necessary, to be consistent with the estimates presented in this report. As a result, more detailed geographical summaries for individual facilities, counties, or Air Quality Control Regions are available from NEDS. For NO_x, similar information will be available following future cross-checking of NEDS and E.H. Pechan data to be completed later in 1982.

The non-utility combustion category includes fuel consumed by industrial, commercial and residential consumers in stationary sources. The industrial combustion estimates are based on fuel use data available only at the State level. Commercial and residential estimates were obtained largely from NEDS, where estimates down to the county level are available.

The transportation category includes emissions from highway motor vehicles and off-highway mobile sources such as aircraft, railroads, vessels and miscellaneous off-highway vehicles. All of these data were derived from NEDS, where estimates down to the county level are available.

Emissions for non-ferrous smelters and other sources are based on data from NEDS and emissions estimates calculated from industrial production data reported in a number of literature references. The category "other sources" includes other industrial processes, solid waste disposal operations, and miscellaneous sources such as forest fires, agricultural burning, and structural fires. For SO_2, the industrial process categories which account for the great majority of emissions from other sources are shown in Table B.2.2. For NO_x, emissions from other sources are negligible compared to emissions from other categories. Nationally, the largest contributors to NO_x emissions from other sources are estimated to be petroleum refineries (21%) and ammonia and nitric acid plants (20%). Remaining emissions are distributed among a number of other source categories.

An analysis was performed to estimate the probable error inherent in the emission estimates of SO_2 and NO_x. The results are summarized in Appendix 3. The probable error in the total national SO_2 emissions was estimated to be 2.3% and for NO_x, was estimated to be 2.0%. The probable errors are estimates of the probable variation of the emissions estimates from "true" emissions values, as a result of the imprecision of data used to compile the emissions estimates and biases inherent in the estimation methodology. The reported probable errors are approximations derived through a combination of statistical theory and engineering judgement. They do not represent true error values obtained through the application of rigorous statistical procedures. The methodology for calculation of these probable errors, along with a sample of more detailed results for one state, is presented in Appendix 3.

TABLE B.2.1
1980 U.S. SO_2 Emissions Estimates
(1 000 Metric Tonnes/Year)

State	Electric Utilities	Non-utility Combustion	Non-ferrous Smelters	Trans-portation	Other Sources	State Total
Alabama	492.7	77.7	1.5	12.1	103.5	688.3
Alaska	10.7	2.9	0.0	2.3	1.1	16.9
Arizona	79.4	7.9	699.7	8.5	20.6	816.1
Arkansas	24.1	28.7	12.9	9.2	17.2	92.1
California	70.7	50.6	0.0	91.0	192.7	405.0
Colorado	70.3	21.9	0.0	8.9	18.2	119.3
Connecticut	29.1	31.3	0.0	4.6	0.2	65.2
Delaware	47.6	23.9	0.0	1.9	25.8	99.2
Dist. of Columbia	4.2	7.7	0.0	0.9	0.6	13.4
Florida	658.5	87.9	0.0	38.6	208.3	993.3
Georgia	668.3	39.6	0.0	19.2	34.6	761.7
Hawaii	37.7	7.6	0.0	2.4	5.3	53.0
Idaho	0.0	10.3	17.2	3.7	11.3	42.5
Illinois	1 021.1	171.0	0.0	29.0	113.0	1 334.1
Indiana	1 396.7	263.1	4.5	19.8	137.4	1 821.5
Iowa	209.8	52.1	0.0	10.8	25.5	298.2
Kansas	136.2	10.2	0.0	13.6	42.1	202.1
Kentucky	914.0	60.3	6.3	13.0	23.1	1 016.7
Louisiana	22.5	69.4	5.4	27.8	150.9	276.0
Maine	14.8	59.0	0.0	3.2	9.0	86.0
Maryland	202.5	50.9	5.1	13.2	34.9	306.6
Massachusetts	249.9	52.5	0.0	9.3	0.8	312.5
Michigan	512.9	139.6	65.0	18.1	87.1	822.7
Minnesota	160.9	39.7	0.0	13.1	22.5	236.2
Mississippi	117.2	43.6	0.0	16.2	81.5	258.5
Missouri	1 034.7	49.9	26.8	17.2	51.8	1 180.4
Montana	21.2	22.9	78.0	5.0	21.5	148.6
Nebraska	44.9	3.9	0.0	9.2	10.0	68.0
Nevada	30.5	1.6	181.4	2.7	4.0	220.2
New Hampshire	73.0	9.1	0.0	1.4	0.8	84.3
New Jersey	100.0	67.6	0.0	22.9	62.8	253.3
New Mexico	76.8	2.0	57.4	8.5	99.0	243.7
New York	435.7	303.5	5.7	34.5	77.3	856.7
North Carolina	395.0	105.1	1.3	16.4	28.6	546.4
North Dakota	77.8	11.5	0.0	4.1	3.4	96.8
Ohio	1 970.1	281.7	6.8	31.3	111.2	2 401.1
Oklahoma	34.2	13.5	0.0	11.5	50.2	109.4
Oregon	3.0	22.8	3.6	13.5	11.6	54.5
Pennsylvania	1 330.1	230.2	2.7	33.9	237.6	1 834.5
Rhode Island	4.7	7.3	0.0	1.5	0.3	13.8
South Carolina	193.3	76.5	0.0	8.9	17.1	295.8
South Dakota	26.0	2.8	0.0	3.6	3.2	35.6
Tennessee	847.1	74.9	5.1	15.7	33.8	976.6
Texas	274.7	96.6	78.6	87.5	620.8	1 158.2
Utah	20.1	14.8	4.0	5.4	21.1	65.4
Vermont	0.5	4.4	0.0	1.3	0.0	6.2
Virginia	148.5	128.7	0.0	23.2	27.1	327.5
Washington	63.0	37.5	97.0	19.0	30.2	246.7
West Virginia	856.6	76.6	8.2	6.4	39.0	986.8
Wisconsin	440.6	96.9	0.0	13.2	27.5	578.2
Wyoming	106.7	26.8	0.0	6.2	27.0	166.7
TOTAL	15 760.5	3 178.8	1 374.4	795.8	2 982.7	24 092.2

TABLE B.2.2
1980 U.S. SO_2 Emission Estimates
Major Categories Included in "Other Sources"
(1 000 Metric Tonnes/Year)

State	Petroleum Refining	Cement Plants	Nat. Gas Plants	Iron & Steel	H_2SO_4 Plants
Alabama	1.0	19.6	34.9	27.7	1.4
Alaska	1.2	0.0	0.0	0.0	0.0
Arizona	0.0	7.7	0.0	0.0	6.4
Arkansas	4.5	7.1	0.6	0.0	1.5
California	114.7	50.0	0.0	5.9	7.9
Colorado	1.7	10.5	0.0	3.1	0.0
Connecticut	0.0	0.0	0.0	0.0	0.0
Delaware	20.2	0.0	0.0	0.0	2.3
Dist. of Columbia	0.0	0.0	0.0	0.0	0.0
Florida	0.1	32.9	28.8	0.0	82.6
Georgia	0.4	9.3	0.0	0.0	3.1
Hawaii	2.4	2.4	0.0	0.0	0.2
Idaho	0.0	1.3	0.0	0.0	8.8
Illinois	68.6	18.7	0.0	13.8	6.7
Indiana	35.4	22.8	0.0	70.1	4.1
Iowa	0.0	21.6	0.0	0.0	3.0
Kansas	17.8	17.4	0.0	0.0	0.5
Kentucky	9.8	4.4	0.0	4.4	1.3
Louisiana	90.3	7.7	1.8	0.0	33.5
Maine	0.0	3.0	0.0	0.0	0.3
Maryland	0.8	15.3	0.0	15.0	1.6
Massachusetts	0.0	0.0	0.0	0.0	0.5
Michigan	7.5	42.2	1.2	21.8	0.4
Minnesota	16.0	0.0	0.0	0.0	0.0
Mississippi	14.4	4.5	43.0	0.0	6.5
Missouri	7.5	36.4	0.0	1.2	1.2
Montana	11.0	3.8	0.0	0.0	1.4
Nebraska	0.3	3.8	0.0	0.0	0.0
Nevada	0.0	2.4	0.0	0.0	0.0
New Hampshire	0.3	0.0	0.0	0.0	0.0
New Jersey	31.9	0.0	0.0	0.0	6.5
New Mexico	2.6	1.8	85.3	0.0	3.1
New York	6.4	33.5	0.0	18.1	0.5
North Carolina	0.1	4.0	0.0	0.0	15.2
North Dakota	3.3	0.0	0.0	0.0	0.0
Ohio	26.4	16.5	0.0	54.6	3.2
Oklahoma	35.5	11.5	0.0	0.0	0.5
Oregon	0.2	3.5	0.0	0.0	0.0
Pennsylvania	45.6	56.3	0.0	110.1	1.9
Rhode Island	0.0	0.0	0.0	0.0	0.0
South Carolina	0.0	11.5	0.0	0.0	0.3
South Dakota	0.0	2.8	0.0	0.0	0.0
Tennessee	0.4	10.2	0.0	0.6	8.2
Texas	281.5	62.5	206.2	7.2	16.4
Utah	9.7	3.3	0.0	5.0	2.7
Vermont	0.0	0.0	0.0	0.0	0.0
Virginia	4.4	4.2	0.0	0.0	4.1
Washington	14.2	7.9	0.0	0.0	0.4
West Virginia	0.8	6.4	0.0	23.2	0.7
Wisconsin	1.3	2.3	0.0	1.2	0.0
Wyoming	18.3	2.0	5.4	0.0	0.5
TOTAL	908.4	594.8	407.1	382.9	239.1

TABLE B.2.3
1980 U.S. NO_x Emissions Estimates
(1 000 Metric Tonnes/Year)

State	Electric Utilities	Non-utility Combustion	Non-ferrous Smelters	Trans-portation	Other Sources	State Total
Alabama	155.8	75.6	0.0	148.7	28.5	408.6
Alaska	0.0	24.7	0.0	24.1	3.4	52.2
Arizona	82.2	35.9	0.0	107.9	7.8	233.8
Arkansas	24.0	40.5	0.0	119.0	13.7	197.2
California	104.7	186.3	0.0	743.7	76.7	1 111.4
Colorado	77.9	60.7	0.0	104.0	8.2	250.8
Connecticut	18.5	20.8	0.0	81.5	0.8	121.6
Delaware	17.6	7.8	0.0	19.9	1.8	47.1
Dist. of Columbia	1.4	5.1	0.0	12.7	0.7	19.9
Florida	194.0	47.2	0.0	314.9	31.9	588.0
Georgia	171.4	35.1	0.0	214.0	27.8	448.3
Hawaii	12.1	2.5	0.0	23.6	2.8	41.0
Idaho	0.0	13.2	0.0	47.0	13.6	73.8
Illinois	377.1	117.1	0.0	385.7	32.1	912.0
Indiana	327.8	89.7	0.0	254.3	29.5	701.3
Iowa	89.3	42.9	0.0	150.1	8.6	290.9
Kansas	77.7	137.4	0.0	159.8	21.7	396.6
Kentucky	246.8	60.6	0.0	166.0	8.6	482.0
Louisiana	88.8	500.7	0.0	172.4	80.3	842.2
Maine	1.0	12.2	0.0	37.7	3.0	53.9
Maryland	55.2	33.5	0.0	129.7	6.7	225.1
Massachusetts	51.8	33.3	0.0	143.1	1.8	230.0
Michigan	215.4	109.4	0.0	274.4	26.7	625.9
Minnesota	101.2	48.1	0.0	181.8	7.7	338.8
Mississippi	45.6	72.0	0.0	113.2	28.0	258.8
Missouri	215.0	44.9	0.0	230.4	24.6	514.9
Montana	20.8	20.0	0.0	56.8	16.4	114.0
Nebraska	36.0	20.0	0.0	112.8	7.7	176.5
Nevada	38.9	3.4	0.0	32.0	1.2	75.5
New Hampshire	22.3	3.4	0.0	24.2	0.7	50.6
New Jersey	59.7	61.9	0.0	223.6	23.1	368.3
New Mexico	72.4	99.2	0.0	87.6	3.6	262.8
New York	117.7	126.5	0.0	348.9	23.4	616.5
North Carolina	194.5	45.0	0.0	229.8	17.2	486.5
North Dakota	48.1	9.6	0.0	54.1	1.3	113.1
Ohio	468.0	147.0	0.0	397.4	26.0	1 038.4
Oklahoma	94.9	196.4	0.0	163.8	21.9	477.0
Oregon	2.5	23.0	0.0	130.6	18.1	174.2
Pennsylvania	354.2	149.0	0.0	393.9	44.1	941.2
Rhode Island	2.6	4.7	0.0	25.5	0.3	33.1
South Carolina	76.5	35.3	0.0	114.8	9.5	236.1
South Dakota	19.0	3.2	0.0	52.5	6.1	80.8
Tennessee	181.8	62.2	0.0	202.8	22.4	469.2
Texas	473.2	1 010.0	0.0	676.2	148.3	2 307.7
Utah	35.2	29.9	0.0	59.1	6.6	130.8
Vermont	0.5	1.9	0.0	19.6	0.4	22.4
Virginia	55.8	59.0	0.0	226.8	25.5	367.1
Washington	22.5	28.6	0.0	175.2	35.8	262.1
West Virginia	273.8	49.6	0.0	78.6	8.3	410.3
Wisconsin	131.3	51.8	0.0	188.7	9.6	381.4
Wyoming	93.0	70.5	0.0	62.7	5.2	231.4
TOTAL	5 647.5	4 168.6	0.0	8 500.5	976.5	19 293.1

B.2.2 Canada

The data base for the baseline 1980 emission estimates of SO_2 and NO_x are a mixture of data covering the years 1978 and 1980. For sulfur dioxide, area source information represents 1978 annual emission rates. Major point sources are at their 1980 annual emission rates, accounting for approximately 67% of the Canadian total, for SO_2. These sources are in the following sectors: non-ferrous smelting, power generation, iron ore sintering, natural gas processing and tar sands operations. For nitrogen oxides, expressed as NO_2, all area sources and most point source emissions are from the 1978 base year. Emissions estimates for power plants east of Manitoba are at their 1980 levels. It is anticipated that the NO_x emissions inventory for 1980 will not be significantly different than that presented in this report.

Emissions have been estimated for SO_2 and NO_x according to the following categories:

1) Non-ferrous smelting - This includes copper/nickel smelters, lead/zinc smelters and primary aluminum smelters;

2) Power generation by utilities;

3) Non-utility fuel combustion - This includes combustion emissions from the use of fuels for residential, commercial and industrial purposes. Fuelwood combustion emissions have also been included here;

4) Transportation - This category gives estimates of SO_2 and NO_x emissions from the following transportation sectors: gasoline-powered motor vehicles, railroads, marine, aircraft, off-road use of gasoline and diesel-powered engines;

5) Petroleum refining - Emissions from the refineries' process operations are included in this category; fuel combustion emissions are included under the non-utility fuels combustion sector;

6) Natural gas processing - This category includes emissions from natural gas processing plants, the bulk of which are located in the province of Alberta;

7) Tar Sands operations - Emissions from Canada's two synthetic crude oil plants, located in Alberta, are estimated under this category; and

8) Other - Other industrial processes and incineration plants have been combined in this category.

A description of the methodologies used in the estimation of SO_2 and NO_x emissions, in addition to the assumptions and references used, is given for each of the categories listed above in Appendix 2.

Canadian SO_2 and NO_x emissions are presented in Tables B.2.4 and B.2.5 by province and emission source regions. The emission source regions shown in Figure B.2.1 are those used in the development of transfer matrices by Work Group 2.

A three step approach was used to determine the precision of the SO_2 and NO_x emission data. A check for bias errors or omissions was initially undertaken on the completed inventory and corrections were made where required. Systematic errors were then determined for each major point source and for each major sector on a provincial and source region basis based on an engineering analysis of the parameters that influence the computed emissions. Thirdly, a weighted sensitivity analysis was used to calculate the precision of the nation-wide, provincial, and source region total emissions. Details of the error analysis can be found in Appendix 3.

The precision of the SO_2 Canadian inventory was found to be 6.1 percent and of the NO_x inventory, 10.3 percent. Precisions of provincial and source region inventories for SO_2 and NO_x are summarized in Appendix 3.

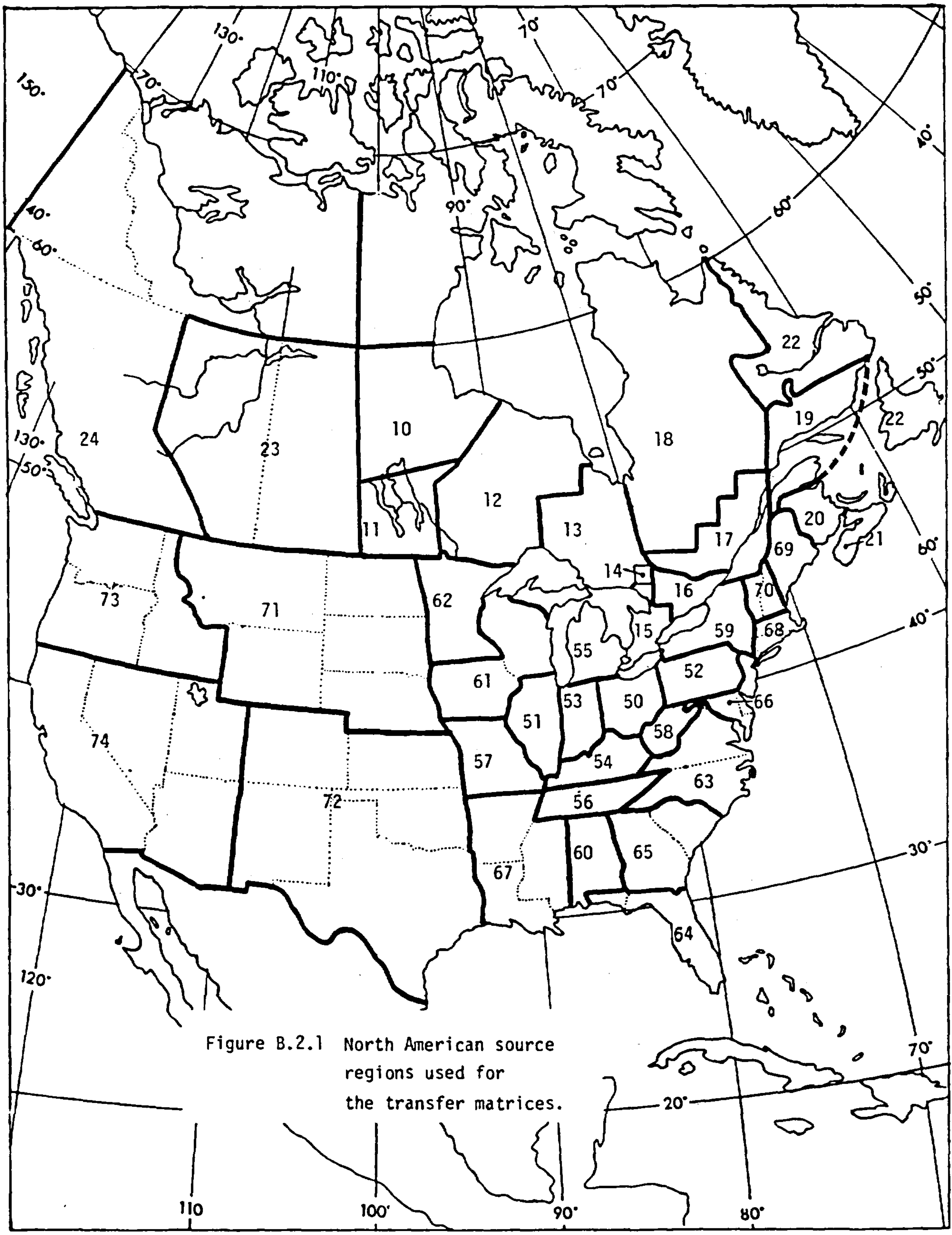

Figure B.2.1 North American source regions used for the transfer matrices.

TABLE B.2.4

Canadian SO_2 Emissions for 1980, In Tonnes (By Province and Source Region)

PROVINCE	REGION	NON-FERROUS SMELTING	POWER GENERATION	NON-UTILITY FUEL COMBUSTION	TRANSPORTATION	PETROLEUM REFINING	NATURAL GAS PROCESSING	TAR SANDS OPERATIONS	OTHER	SUB-TOTAL	PROVINCIAL TOTAL
Manitoba	10	462 607	5	554	635				314	464 115	
Manitoba	11		2 647	8 690	9 420	2 203			2 843	25 803	489 918
Ontario	12		9 730	3 976	5 069				6 067	24 842	
Ontario	13	1 530		6 087	3 088				169 475	180 180	
Ontario	14	934 425		4 635	771				7	939 838	
Ontario	15	833	387 448	178 212	32 645	32 661	186		18 775	650 760	
Ontario	16		324	25 229	6 989				2 463	35 005	1 830 625
Quebec	17	47 543	1 927	334 049	31 161	23 833			28 721	467 234	
Quebec	18	537 505	10	9 761	679				11 807	559 762	
Quebec	19	95 867	14	11 956	16 251				6 832	130 920	1 157 916
New Brunswick	20	12 826	122 353	55 549	3 473	5 513			15 714	215 428	215 428
Nova Scotia	21		124 249	70 145	4 595	10 147			9 645	218 781	218 781
P.E.I.	21		3 013	2 281	498				2	5 794	5 794
Newfoundland	22		20 462	33 725	2 080				4 658	60 925	60 925
Saskatchewan	23		36 998	7 936	9 165	1 712	255		1 730	57 796	57 796
Alberta	23		35 073	16 218	17 460	3 178	315 426	128 188	23 814	539 357	539 357
British Columbia*	24	32 139	646	56 961	14 077	9 901	63 544		15 600	192 868	192 868
TOTAL CANADA		2 125 275	744 899	825 964	158 056	89 148	379 411	128 188	318 467	4 769 408	4 769 408

*B.C. includes Yukon - N.W.T.

TABLE B.2.5

Canadian NO_x Emissions for 1980, In Tonnes (By Province and Source Region)

PROVINCE	REGION	NON-FERROUS SMELTING	POWER GENERATION	NON-UTILITY FUEL COMBUSTION	TRANSPORTATION	PETROLEUM REFINING	NATURAL GAS PROCESSING	TAR SANDS OPERATIONS	OTHER	SUB-TOTAL	PROVINCIAL TOTAL
Manitoba	10		49	489	4 249				871	5 658	
Manitoba	11		3 150	6 708	61 220	71			1 350	72 499	78 157
Ontario	12		1 549	2 322	11 641				2 964	18 476	
Ontario	13			3 338	13 521				1 675	18 534	
Ontario	14			2 354	7 632				55	10 041	
Ontario	15		99 309	80 340	235 296	1 190			1 431	417 566	536 469
Ontario	16		102	13 711	56 647				1 392	71 852	
Quebec	17	4 988	2 180	87 607	195 736	1 180			3 448	295 139	
Quebec	18		73	2 723	7 796				2 347	12 939	
Quebec	19	1 265	107	3 396	17 667				845	23 280	331 358
New Brunswick	20		16 808	12 883	27 567	179			1 810	59 247	59 247
Nova Scotia	21		39 342	15 292	32 449	347			699	88 129	88 129
P.E.I.	21		1 045	676	5 104				24	6 849	6 849
Newfoundland	22		3 663	8 363	18 753				369	31 148	31 148
Saskatchewan	23		37 697	10 030	95 641	94			4 802	148 264	148 264
Alberta	23		35 585	115 771	181 034	777		13 653	6 643	353 463	353 463
British Columbia*	24	2 135	4 528	28 675	142 426	435			20 769	198 968	198 968
TOTAL CANADA		8 388	245 187	394 678	1 114 379	4 273	0	13 653	51 494	1 832 052	1 832 052

*B.C. includes Yukon - N.W.T.

*NO_x: Expressed as NO_2

B.3 PROJECTED EMISSIONS (SO_2 AND NO_x)

B.3.1 United States

Projections of emission baselines for utility and non-utility sectors continue to be updated and have been expanded since the publication of the U.S./Canadian Interim Report in February, 1981. Two sets of projections are presented here. First, national emission projections are provided by sector in Table B.3.1-A and Table B.3.1-B. Second, state-level total emission projections, aggregating all sectors for each state, are presented in Table B.3.2-A and B.3.2-B, as specified in the terms of reference of the Work Group.

These state-level projections of emissions were made using different models for each sector, as summarized in Table B.3.3. These models generally agree on the growth rate assumptions and reflect GNP growth in the range of 2 to 3 percent/year. However, a variety of methods, data bases of various vintages, and range of state and regional growth rates were used for each sector. An effort to cross-check all of these assumptions and the implied changes in fuel prices and demand elasticities has not been made.

The following discussion presents the methodologies and assumptions used for making emissions projections for each of the sectors individually. A more comprehensive discussion is found in Appendix 6.

The state-by-state estimates should be used with considerable caution. Generally, state-by-state projections within a sector are subject to even greater uncertainty than national projections for that sector, as decisions to shift locations of combustion activity, either individual plants, industries, or population can represent a large percentage change in total emissions for a state. Furthermore, the limits to our knowledge of current emissions sources, which serve as a basis for state level projections, will constrain our projections. The reliability of state-level data will vary by sector. These and other uncertainties and constraints for each sector are discussed in Section E.

New projections for utility emissions are based upon the new 1980 utility plant data for individual units, and new assumptions about future demand growth. Assumptions concerning coal usage by industrial combustors are of primary importance to SO_2 emission projections; recent estimates of industrial coal use are significantly more conservative than those of early 1981. Recent smelter closings have also caused us to revise emission projections from that sector. Emission projections for the Residential/Commercial, Transportation, and Industrial Process sectors have been updated based on revised energy demand published in the NEP in July, 1981.

TABLE B.3.1-A

UNITED STATES

National Current and Projected SO_2 Emissions Using Combined Models (10^6 tonnes/yr.)

	Current 1980	Projected 1990	Projected 2000
Electric Utilities	15.8	15.9	16.2
Industrial Boilers & Process Heaters	2.4*	3.5	6.5
Non-ferrous Smelters	1.4	0.5	0.5
Residential/Commercial	0.8	1.0	0.9
Other Industrial Processes	2.9*	1.2	1.4
Transportation	0.8	0.8	1.0
TOTAL U.S.	24.1	22.9	26.6

*In current 1980 emissions, process heaters are included with other industrial processes and not with industrial boilers.

Source of projections: These emissions estimates are based on the following sources for projections for each sector: utility - EHPA; industrial - ICF, Res/Com - SEAS; Smelters - site by site survey; Industrial Processes - SEAS; Transportation - SEAS.

TABLE B.3.1-B

UNITED STATES

National Current and Projected NO_x Emissions Using Combined Models (10^6 tonnes/yr.)

	Current 1980	Projected 1990	Projected 2000
Electric Utilities	5.6	7.2	8.7
Industrial Boilers & Process Heaters	3.5*	3.0	4.0
Residential/Commercial	0.7	0.7	0.6
Industrial Processes	0.7*	0.8	1.1
Transportation	8.5	7.8	9.7
Miscellaneous	0.3	- **	- **
TOTAL U.S.	19.3	19.5	24.1

*In current 1980 emissions, process heaters are included with industrial processes and not with industrial boilers.

**Projections of emissions from miscellaneous sources (solid waste disposal, forest fires, etc.) were not produced.

Source of projections: These emissions projections are based on the following sources for projections for each sector: utility - EHPA; Industrial boilers and process heaters - ICF; Res/Com - SEAS; Industrial Processes - SEAS; Transportation - Mobile 2.

TABLE B.3.2.A

All Sectors by State
Projected SO_2 Emissions using Combined Models
(10^3 metric tonnes)

New England	1990	2000
Connecticut	66.5	101.9
Maine	62.4	81.0
Massachusetts	228.6	240.9
New Hampshire	87.8	85.7
Rhode Island	20.8	20.4
Vermont	14.0	9.4
Regional Total	480.0	543.8
Mid Atlantic		
New York	772.6	740.1
New Jersey	272.6	463.3
Pennsylvania	1 824.6	1 897.4
Regional Total	2 825.8	3 096.9
South Atlantic		
Delaware	59.9	65.9
D.C.	18.1	16.8
Florida	889.0	1 091.9
Georgia	876.6	1 007.5
Maryland	333.6	414.9
North Carolina	615.1	758.7
South Carolina	357.2	456.6
Virginia	319.7	362.8
W. Virginia	1 007.8	1 120.6
Regional Total	4 475.9	5 295.5
East South Central		
Alabama	683.0	792.0
Kentucky	732.3	788.2
Mississippi	202.3	243.5
Tennessee	898.5	997.3
Regional Total	2 516.1	2 858.1
Pacific		
California	347.0	444.5
Oregon	61.8	99.9
Washington	170.1	214.4
Regional Total	578.8	759.0

East North Central	1990	2000
Illinois	1 457.6	1 674.8
Indiana	1 493.6	1 434.3
Michigan	790.8	971.9
Ohio	2 267.5	2 415.2
Wisconsin	938.1	992.5
Regional Total	6 974.1	7 557.2
West South Central		
Arkansas	127.6	234.7
Louisiana	392.4	754.3
Oklahoma	118.8	128.6
Texas	996.0	1 660.5
Regional Total	1 635.8	2 778.2
West North Central		
Iowa	312.4	399.9
Kansas	220.6	281.5
Minnesota	235.2	291.2
Missouri	1 162.3	1 226.9
Nebraska	87.4	103.8
North Dakota	125.6	202.1
South Dakota	34.2	51.1
Regional Total	2 176.9	2 545.1
Mountain		
Arizona	519.7	441.2
Colorado	179.6	218.0
Idaho	69.8	109.3
Montana	48.0	78.6
Nevada	59.6	61.3
New Mexico	190.3	209.3
Utah	141.4	164.7
Wyoming	110.5	121.7
Regional Total	1 314.0	1 403.4
TOTAL U.S.	22 977.4	26 638.0

NOTE: Number may not equal totals due to rounding

TABLE B.3.2.B

All Sectors by State
Projected NO_x Emissions using Combined Models
(10^3 metric tonnes)

New England	1990	2000
Connecticut	156	199
Maine	76	92
Massachusetts	308	378
New Hampshire	62	69
Rhode Island	43	50
Vermont	24	29
Regional Total	669	815
Mid Atlantic		
New York	747	848
New Jersey	501	615
Pennsylvania	1 068	1 219
Regional Total	2 317	2 680
South Atlantic		
Delaware	54	65
D.C.	31	42
Florida	683	960
Georgia	582	703
Maryland	265	351
North Carolina	479	649
South Carolina	264	307
Virginia	350	430
W. Virginia	471	581
Regional Total	3 180	4 088
East South Central		
Alabama	424	530
Kentucky	469	558
Mississippi	177	199
Tennessee	475	558
Regional Total	1 544	1 846
Pacific		
California	1 284	1 531
Oregon	152	217
Washington	249	403
Regional Total	1 685	2 151

East North Central	1990	2000
Illinois	1 038	1 245
Indiana	746	861
Michigan	720	905
Ohio	1 195	1 545
Wisconsin	496	561
Regional Total	4 196	5 116
West South Central		
Arkansas	189	267
Louisiana	529	678
Oklahoma	333	442
Texas	1 814	2 351
Regional Total	2 865	3 737
West North Central		
Iowa	268	325
Kansas	258	299
Minnesota	313	404
Missouri	466	541
Nebraska	130	156
North Dakota	136	283
South Dakota	67	84
Regional Total	1 621	2 091
Mountain		
Arizona	251	334
Colorado	241	324
Idaho	46	66
Montana	95	187
Nevada	95	126
New Mexico	180	252
Utah	129	188
Wyoming	152	205
Regional Total	1 188	1 685
TOTAL U.S.	19 265	24 209

Source: Combined Models, see text.

NOTE: Number may not equal totals due to rounding

TABLE B.3.3

Comparison of Methodology and Assumptions for Combined Models of SO_2 and NO_x Emission Projections by Sector

Sector	Methodology	Base Year Demand	Growth Rate Assumptions	Source of Disaggregated Data
Utility	EHPA	1980 Unit Inventory of emissions estimates by quantity and quality of fuel burned.	Electricity demand: 1980-85 - 1.5%/yr. 1986-2000 - 2.7%/yr.	Electricity demand growth by state
Industrial Boilers	IBM	1974 Survey of large combustors. Annual sales survey of boiler purchases by manufacturers (ASM)	Varies by major industry, reflecting GNP growth of: 1974-82 - 2.7%/yr. 1983-2000 - 3.0%/yr. Reduced to 1.9%/yr. to reflect conservation.	Regionalized by BEA and OBERS regional economic growth projections.
Industrial Process Heaters	PHM	Same as IBM	Same as IBM	Same as IBM
Smelters	Los Alamos, and Others	Site-by-site survey	Demand growth of 2-3% year depending on type of smelter.	Site-by-site analysis
Residential/ Commercial	SEAS	NEDS	Assumes total energy use decline by household of: 1980-90 - 1.8%/yr. due to conservation	BEA data on population shifts and building characteristics.
Industrial Processes	SEAS	1972 Census of Manufacturers updated by Bureau of Commerce	Varies by Industry: 1975-2000 - steel - 2.1%/yr.; stone & clay - 1.6%/yr.; chemicals - 2.8%/yr.	BEA and OBERS

TABLE B.3.3 (continued)

Comparison of Methodology and Assumptions for Combined Models of SO_2 and NO_x Emission Projections by Sector

Sector	Methodology	Base Year Demand	Growth Rate Assumptions	Source of Disaggregated Data
Transportation	MOBILE 2 - NO_x	1977 NEDS data	VMT projections vary by vehicle type: LDV - +1.4%/yr. LDT - +4.6%/yr. HDG - -2.0%/yr. HDD - +5.0%/yr. Off Highway - +2.5%/yr.	SEAS state fractions developed from data on inter city travel and population projections.
	SEAS - SO_2	1975 NEDS data	Overall energy demand 1980-90 - -0.5%/yr. 1991-2000 - +0.4%/yr.	Same as above

A major difference between this report and the interim report is that no policy scenarios are presented here. We have attempted to refine baseline emission projections, estimating emissions to the year 2000 assuming no change in current regulations. As in the previous report, we conclude that utilities are the dominant source of SO_2 and will remain so for the next 20 years. For NO_x, the transportation contribution is, and will remain slightly higher than that for electric utilities.

B.3.1.1 Electric Utilities

Electric utility plants fired by fossil fuels are projected to continue contributing the greatest amount of SO_2 emissions, as well as significant amounts of NO_x. The methodology chosen for projecting utility emissions was developed by E.H. Pechan & Associates, and allowed us to take advantage of the new 1980 utility data base developed for the current emissions estimates. This set of projections uses the 1980 data base with current plant capacity, capacity utilization, emissions, and planned additions to project future emissions, using assumed rates of growth in electricity demand, assumed retirements and capacity utilization rates, as outlined below.

This methodology differs from previous methodologies and other ongoing work used to project utility emissions. The previous national projections presented in the Phase I report came from a variety of simulation models which projected utility fuel use and generation by fuel type based on assumptions about fuel and generation costs and growth in overall energy demand (See Section E). The methodology employed for these projections does not use a simulation or optimization model and thus does not project changes in utility operating behavior, plans for new construction or plans to purchase power that would occur because of projected changes in costs of existing and new generation. Rather, the chosen methodology implicitly assumes that current economic and non-economic factors will not change dramatically.

Table B.3.4 presents emissions and fuel use for the nation, while Tables 6.1 and 6.2 in Appendix 6 present results on a state-by-state basis. As noted above, state-by-state projections are subject to substantially more uncertainty than more aggregated data. National fuel use by fuel type changes considerably as coal use doubles by 2000, nuclear power is projected to nearly triple and oil and gas use declines by over half. For the nation, both SO_2 and NO_x emissions increase, with NO_x emissions increasing by 50% over 1980 levels by 2000. SO_2 emissions do not increase as dramatically. The increase in SO_2 emissions due to growth by 1990 are almost entirely offset by reductions from compliance with state implementation plan requirements by existing plants. Critical assumptions are discussed in Appendix 6. A summary of these assumptions is presented below.

Table B.3.4

National Projections of Utility Emissions & Fuel Use

	1980	1990	2000
SO_2 Emissions (million tonnes)	15.8	15.9	15.9
NO_x Emissions (million tonnes)	5.6	7.2	8.7
Coal Use (10^{15} Btus)	11.9	15.9	24.1
Oil Use (10^{15} Btus)	2.7	2.2	1.2
Gas Use (10^{15} Btus)	3.7	2.7	1.6
Nuclear Power (10^{15} Btus)	2.5	5.0	7.2
Hydro, Other (10^{15} Btus)	3.1	3.5	4.6
Generation (10^{12} kwh)	2 290	2 840	3 740

i) Electricity Demand Growth Rates

Electricity demand growth rates were assumed to be 1.5% per year from 1981-1985 and 2.7% per year over the remaining period. These assumed growth rates reflect continuation of the nearly flat generation growth over the past few years until 1985 followed by a period of increase at annual rates equivalent to DOE mid-range projections from the NEPP.

These growth rates were assumed to vary slightly by region with higher growth rates in the West, West South Central and Mountain areas and lower than average in the East. The differential regional growth rates were adopted from previous USM model runs (See Section E), which provided state-by-state growth rates based on the Bureau of Economic Analysis Estimates of growth in regional economic activity. These trends are supported by the regional Electric Reliability Councils which project higher rates of demand growth in these regions. Table B.3.5 illustrates projected electricity generation by region. For these projections, current baseload/peakload ratios were maintained in each state.

ii) Plant Life and Capacity Retirements

Plant lifetimes for existing plants were specified by each utility company by unit. No plants currently on line were allowed to retire before 1991 unless plans were already announced that they were scheduled to do so. For those plants without utility-specified lifetimes, a 50 year plant life was assumed for coal steam plants, and a 35 year life for all other steam plants.

iii) Planned Capacity

This analysis specifies all planned additions by unit based on announced plans by utilities as provided to the Electric Reliability Councils. Nuclear steam capacity by unit was specified by DOE Energy Information Administration, which provides information by unit including announced on-line dates. Scheduled plants were brought on line to meet new demand requirements.

iv) Capacity Factors

All existing plants were maintained at historical capacity factors. Existing oil and gas steam plants however were reduced as listed to reflect gradual scaling back of operation due to high operating costs. New nuclear and fossil steam plants were assumed to operate at .65 capacity factor. New oil and gas non-steam plants were assumed to operate at 0.10 capacity.

v) Reconversions of Oil Steam Plants to Coal

Many of the oil steam plants in New England and the Mid Atlantic States were originally designed to burn coal and were later converted to oil. In the base case, we assume that 15

Table B.3.5

Projected Generation by Census Region

(Terawatt hours)

	1990	2000
New England	89	104
Middle Atlantic	301	353
East North Central	500	665
West North Central	211	281
South Atlantic	524	695
East South Central	260	332
West South Central	410	576
Mountain	215	310
Pacific	331	424
TOTAL UNITED STATES	2 840	3 739

Note: Numbers do not equal totals due to rounding.

Gigawatts of such capacity will be converted to coal. This includes 8.4 GW of announced conversion capacity (through 1991) provided by the National Electric Reliability Council,* plus additional assumed capacity conversions occurring largely through the East.

* National Electric Reliability Council, "Electric Power Supply and Demand, 1981-1990", July 1981.

vi) **Emission Rates**

For currently operating units, actual emissions were calculated based on the methodology stated in the previous section on Implementation Plans (SIP) as average annual limits. Emission rates for all plants built and operating through 1980 are based on actual rates. All plants were assumed to comply with SIP limits to be approved.

For new plants built before 1971, several assumptions must be made about emission standards and fuel type used. New electric power plants can be subject to either of two emission standards, which apply by fuel type, depending on when they commenced construction. The first standard is applicable to plants beginning construction between August 17, 1971 and September 18, 1978. The second applies to plants commencing construction after September 18, 1978. A full discussion of these standards and how they are applied is found in Appendix 6.

All new plants scheduled to come on line after 1983 were assumed to be subject to the revised NSPS limit. All western states (west of North Dakota through Texas) were assumed to scrub their emissions 90% to meet stricter PSD limits, resulting in emissions rates of 0.6 lbs SO_2/MM Btu or less, depending on coal type used.

B.3.1.2 Industrial Boilers and Process Heaters

Of the non-utility sectors, industrial combustors contribute the greatest amount of SO_2. Two models developed by ICF, Inc., the Industrial Boiler Model (IBM) and the Process Heat Model (PHM), were used to project SO_2 and NO_x emissions from industrial combustors. The following discussion is derived from two draft studies by ICF, Inc. (1,2).

The IBM simulates a manufacturer's decision when choosing among different types of fuel prior to construction of a new boiler. The most important model parameters are economic - fuel price, boiler capital cost, operating and maintenance costs; regulatory - New Source Performance Standards (NSPS), SIP, Non-Attainment Policy (NAP), and technological - physical constraints precluding the use of coal.

The PHM is more of an accounting system than a predictive model, i.e., the process heater population is assumed to remain almost static in terms of types of fuel being used. Economic growth factors are assumed for different industries to reflect increased energy demand, however, greatly increased coal use by process heaters is not anticipated due to technological constraints. A detailed discussion of assumptions can be found in Appendix 6. Following is a brief summary of these assumptions.

i) Fuel Prices and Equipment Costs

Following are cost assumptions made by ICF preliminary to forecasting fuel demand:

World Oil Price (1980$ per barrel)

1980	1990	2000
34.0	40.8	47.6

Residual Oil Price at the Refinery (1980$ per MMBtu)

	1980	1990	2000
(Medium Sulfur Content)	5.33	6.23	7.57

Natural Gas Price at the Refinery (1980$ per MMBtu)

1990	2000
5.60	7.36

ii) Environmental Regulations

Twenty-nine fuel types were available for selection in the IBM. These fuel types are shown in Appendix 6. Some of these were precluded from use due to environmental regulations, such as SIP, NSPS, and NAP.

iii) Characteristics of the Combustor Population

After assumptions regarding fuel and equipment costs and regulatory constraints are made, the next step is to characterize fuel demand in the existing and future boiler population by type of fuel, utilization rate and amount of fuel consumed. A boiler lifetime of 45 years was assumed in addition to annual GNP growth of about 3 percent. Sources of data and other major assumptions concerning the existing and future boiler population are discussed in Appendix 6.

The same sources used in the IBM to characterize and distribute energy demand are used for the PHM. However, important differences between the two are stated in the Appendix.

iv) Industrial Energy Demand

Finally, assumptions concerning the existing and future combustor population enable the IBM and PHM to project fuel demand. The results for the U. S. as a whole are included in the following tables:

	Projection (10^{15} Btu)	
	1990	2000
Total Industrial Energy Demand	16.2	18.7
Industrial Boiler Energy Demand	6.2	7.2
Process Heater Energy Demand	10.0	11.5
Boiler Energy Demand by Fuel Type		
Coal	2.3	5.7
Oil	0.0	0.4
Gas	3.9	1.1
By-products	0.0	0.0
Process Heater Energy Demand by fuel type		
Coal	0.6	0.7
Oil	1.5	1.7
Gas	4.7	5.5
By-products	3.2	3.6

v) Fuel Sulfur Content and Emission Factors

With a few exceptions, emission factors included in EPA's AP-42 publication, "Compilation of Air Pollutant Emission Factors", July 1979, are used, together with assumptions concerning the sulfur contents of various coal types and residual oils, to calculate SO_2 and NO_x emissions. Emission factors and sulfur contents of fuel are listed in the Appendix.

After specifying the industry, location of combustor, size, and annual utilization rate, the models make an investment or operating decision concerning fuel choice. In the IBM, the lowest cost alternative is always chosen. Once the fuel characteristics of an existing and future combustor population are determined fuel sulfur contents are estimated and emission factors are used to calculate the projected emissions. Tables 3 and 4 in Appendix 6 present SO_2 and NO_x emissions projections on a state-by-state basis.

B.3.1.3 Primary Non-ferrous Smelters

In 1970, approximately 97 percent of total uncontrolled sulfur oxide emissions attributed to non-ferrous smelting was released by smelters west of the Mississippi River. Los Alamos Scientific Laboratory projected SO_2 emissions anticipated from western smelters in 1990 and 2000 based on a site-by-site survey, considerations of federal and state regulations, and technological and economic factors. Assumptions concerning future production capacity and sulfur contents of ore were essential for the emission calculations. The discussion found in Appendix 6 is taken from the report, "Sulfur Dioxide Emissions from Primary Non-ferrous Smelters in the Western United States", Mangeng and Mead, August 1980.

i) Economic Factors

Copper

Since 1975, there has been a lack of announced capital expenditures or plans to expand smelting capacity. Considering this trend and environmental difficulties associated with reverberatory furnaces, the study made pessimistic estimates of future smelting capacity and production.

In 1990, western copper smelters are assumed to be producing 1,562,000 tonnes of copper. Copper production in 2000 is assumed to be 1,782,000 tonnes.

Lead

Projections concerning lead production rely on growth projections published by the U. S. Bureau of Mines ("Lead," Ryan and Hague, U. S. Dept. of Interior report MCP-9, December 1977.) Lead production in 1990 is projected to be 607 000 tonnes; in 2000, lead production is assumed to be 755 000 tonnes.

Zinc

The Bureau of Mines was also referenced for the forecast of zinc production ("Zinc," Cammarata, U.S. DOI report MCP-12, May 1978). Western zinc production in 1990 is assumed to be 140 000 metric tonnes; in 2000 production is assumed to be 164 000 tonnes.

ii) Regulatory Factors

Any new primary non-ferrous smelters coming on-line must comply with stringent NSPS which allow no greater than 0.065 percent SO_2 by volume in the smelter offgases. Modified or reconstructed sources whose emissions would exceed those of the old source must also comply with NSPS. In addition, each state was required by the 1977 Clean Air Act Amendments to develop SIP which reduce overall atmospheric pollution loading on a continuous basis; dispersion techniques such as supplementary control systems cannot be substituted for continuous emission reduction technology to achieve National Ambient Air Quality Standards (NAAQS). By 1988, all non-ferrous smelters must be in compliance with SIP, which require approximately a 90 percent reduction in SO_2 emissions from uncontrolled levels.

Table 6.5 in Appendix 6 presents SO_2 emissions from smelters on a state basis. NO_x emissions from smelters are negligible and no attempt was made to quantify NO_x from smelters.

The projections assume that technological improvements will be developed and introduced at smelters, and that levels of control presently required by SIP will be installed by 1990. No new smelters are assumed in the projection period although some expansion of existing capacity is assumed to take place. Emissions are calculated with assumed sulfur contents of ore (Table 6.30 in Appendix 6) and assumed production capacities. Uncertainties regarding this analysis and those of the other sectors are discussed in Section E.

B.3.1.4 Residential/Commercial

The U. S. Department of Energy used the SEAS model developed by the Mitre Corporation to project emissions from these sectors. The projections in Tables 6.6 and 6.7 of Appendix 6 assumed energy demand by type of fuel as published in the report, "Energy Projections to the Year 2000", July 1981, which is a supplement to the NEPP. Energy values from the mid-range case were used for the model runs.

The NEPP makes assumptions regarding fuel prices, population growth, and degree of energy conservation, to project fuel consumption. Following are tables of major assumptions concerning the residential/commercial sectors.

Delivered Fuel Prices (1980 $ per MMBtu)

Residential	1980	1990	2000
Distillate	7.04	10.74	14.01
Liquified Gas	6.08	9.39	12.20
Natural Gas	3.83	8.00	9.55
Electricity	15.70	18.10	20.74

Commercial	1980	1990	2000
Distillate	6.31	9.92	13.00
Residual Oil	4.29	8.03	10.68
Liquified Gas	5.91	9.35	12.28
Natural Gas	3.13	7.72	9.28
Electricity	16.06	19.01	22.02

	Population (millions)	Households (millions)	Commercial Floor Space (billions of sq. ft)
1980	227	80	32
1990	249	96	41
2000	266	108	52

	Energy Use Per Household (MMBtu/hr)	Energy Use Per Commercial sq. ft. (MMBtu/hr)
1980	134	0.228
1990	110	0.190
2000	96	0.163

B.3.1.5 Industrial Processes

The industrial process sector includes industrial uses for fuel other than providing heat for steam or for a manufacturing process. An example of such a process is municipal sewage/ waste disposal where fuel is burned to dispose of waste, not to manufacture a product. SO_2 and NO_x emissions from this sector are also due to fugitive losses such as SO_2 emissions from sulfur removal processes at a petroleum refinery. This type of fugitive loss is due to a chemical process and is not related to combustion.

The 1972 Census of Manufacturers and other data from the Department of Commerce are used to determine base year fuel use and industrial activity. Data from the Office of Business Economic Research and Statistics (OBERS) and the Bureau of Economic Analysis (BEA) are used to forecast changes in industrial activity over the period 1980 to 2000. To calculate emissions, AP-42 emission factors are applied to the various process categories.

B.3.1.6 Transportation

The transportation SO_2 and NO_x emission projections in Tables 6.10 and 6.11 of Appendix 6 are derived from two different models. Transportation SO_2 projections come from the SEAS model of the Mitre Corp.; transportation NO_x results from the MOBILE2 Model developed by EPA.

SEAS assumes the following transportation statistics as given in the NEPP to project growth in the transportation sector:

	Energy Consumption (10^{15} Btu)		
	1980	1990	2000
Transportation	18.6	17.6	18.4

	Fuel Prices (1980 $ per MMBtu)		
	1980	1990	2000
Gasoline	9.76	13.35	16.47
Distillate	6.29	10.98	14.37
Residual	4.29	7.76	10.30
Jet Fuel	6.64	10.50	14.04

	Consumption by Type of Fuel (10^{15} Btu)		
	1980	1990	2000
Oil	18.0	16.7	17.2
Natural Gas	0.6	0.7	0.8
Alcohol	-	0.2	0.4
Total	18.6	17.6	18.4

To calculate SO_2 emissions, SEAS applies emission factors developed in the EPA MOBILE1 program and assumes a trace level of 0.044 percent sulfur in gasoline.

For the NO_x projections, EPA also started with a historical base year. The base year statistics come from the 1977 National Emissions Data System (NEDS), maintained by EPA.

MOBILE2 adds percentage growth each year to account for growth in Vehicle Miles Travelled (VMT). The following growth factors were assumed:

Percent Growth per year in VMT	LDV	LDT	HDG	HDD	Off Highway
	+1.4	+4.6	-2.0	+5.0	+2.5

MOBILE2 then applies emission factors to each highway vehicle class. The projected composite emission factors for the entire fleet of vehicles follow:

Composite Emission Factors (g/mi)

Vehicle	Current Standard	1979	1990	1995
LDV	1 g/mi	3.01	1.53	1.37
LDT	2.3 g/mi	3.75	2.05	1.92
HDG	10.7 g/b.hp.hr.	10.02	11.48	11.80
HDD	10.7 g/b.hp.hr	25.59	25.59	25.59

REFERENCES

1. "Coal Use by Industry: A Forecast and Sensitivity Analysis." 1982 U.S. Department of Energy.
2. "Air Pollution Emissions from the Manufacturing Sector." 1981. U.S. Environmental Protection Agency.

B.3.2 Canada

Projections of SO_2 and NO_x emissions for non-ferrous smelters, utilities, non-utility fuel use, transportation and other sectors of the Canadian economy have been revised. The projections take into account new and better information and control regulations promulgated since the Phase I report was prepared. Specifically, the Ontario government has announced control orders that will limit the emissions of SO_2 from the Inco smelter complex in Sudbury to 728 kilotonnes by 1983 and from the thermal utility plants to 390 kilotonnes by 1985 and to 260 kilotonnes by 1990. Although the government of Quebec has indicated a control order to Noranda to reduce SO_2 emissions by 40%, this reduction is not taken into account as the actual order to reduce emissions has not yet been served.

The emission estimates are presented in the following sections together with the assumptions that were used to derive these estimates.

Non-ferrous Smelters

The projected emission estimates for non-ferrous smelters to the year 2000 represent the maximum SO_2 emissions expected assuming:

i) that no additional regulatory control actions, except that noted above, are taken by Canadian authorities;

ii) that Canadian companies do not modernize their existing plants with attendant improvement in SO_2 control;

iii) that metal markets improve enabling the metal producers to operate at production rates for which the maximum permissible SO_2 emission limits are achieved;

iv) assumes a continuous and viable ore supply; and

v) assumes that any new smelter or capacity increase in existing smelters will be fully controlled.

The emission estimates are shown in Table B.3.6.

TABLE B.3.6

Non-ferrous Smelters
Projected Maximum SO_2 Emissions (Kilotonnes)

Province	1980	1985	1990	2000
Newfoundland	----	----	----	----
Prince Edward Island	----	----	----	----
Nova Scotia	----	----	----	----
New Brunswick	13	13	13	13
Quebec	681	681	681	681
Ontario	937	885	885	885
Manitoba	463	707	707	707
Saskatchewan	----	----	----	----
Alberta	----	----	----	----
British Columbia	32	32	32	32
TOTAL CANADA	2 126	2 318	2 318	2 318

Electric Utilities - Thermal Power Generation

The emissions projections for SO_2 and NO_x for the electric utility sector were developed by Environment Canada, Air Pollution Control Directorate, based on generation projections from National Energy Board (NEB), 1981 forecasts. The hydraulic and nuclear capacity factors were estimated from historical data, and for those fossil fuel steam units were found from that part of total generation to be provided by the thermal capacity.

Capacity factors were estimated as follows:

1) Projected 1990 and 2000 provincial generation requirements for each province were obtained from the NEB.

2) Estimated 1980 exports minus imports were added to the firm energy requirements to determine total net generation by each province. It was assumed unless stated otherwise in the tables, that the net amount was constant to 2000 A.D.

3) Generation by hydro and nuclear plants in 1990 and 2000 was estimated for each province by applying historical capacity factors for hydro plants, and an 85 percent capacity factor for nuclear plants to the capacity installed at those periods.

4) Projected 1990 and 2000 hydro and nuclear generations were subtracted from the projected gross energy generation in each province to give projected 1990 and 2000 fossil fuel steam plant electricity generation in each province.

5) Capacity factors were assigned to each new fossil fuel steam unit according to fuel cost and plant age to provide the required estimated 1990 or 2000 electricity generation from those plants.

6) The characteristics - fuel quality - of the fuel consumed were assumed to be similar to those of the level currently being used in these units, as reported to Environment Canada.

7) Emissions were then calculated for thermal generation by province (i.e. excepting Newfoundland and Quebec). For Ontario, emissions are, by Ontario law, to be controlled to the amounts shown in the table.

8) Emissions Limits (guideline recommendation)
New plants only

SO_2 - 0.6 lb./10^6 BTU, or 90%
reduction if inlet SO_2 is greater than 6 lb/10^6 BTU

NO_x - 0.6 lb/10^6 BTU

Particulates - 0.1 lb/10^6 BTU

9) No restrictions on NO_x from existing plants - emission factors are identical to those from similar U.S. installations.

There are no limits assumed on existing and new plants. The range of emissions in practice for SO_2 is from 0.5 lb./106 to about 12 lb./106 BTU (one plant on one local coal).

For NO_x, the range is identical to that from existing U.S. boilers.

10) Thermal station capacity factors vary widely in practice depending on generation needs, repair schedules, forced outages, fuel type, etc. For this exercise, the capacity factors fall into the following ranges:

Newfoundland: After 1985, capacity factor tends to zero because of hydraulic generation capacity.

Nova Scotia: Coal-fired - 70%
Oil-fired - 48%

New Brunswick: including (P.E.I) Coal-fired - 60/70%
Oil-fired - 30%

Québec: Zero capacity factor, only hydro generation throughout period

Ontario: Emissions will be from coal firing only, as gas and oil plants will be closed down. Expected range of capacity factor 30-70%

Manitoba: Coal only: 45-70% capacity factor.

Saskatchewan: Coal only: 55-71% capacity factor

Alberta: Coal: 70% capacity factor
Gas: 60% capacity factor

B.C.: Coal: 25-70% capacity factor
Gas: 70% capacity factor

The projected emission estimates are shown in Table B.3.7, while the relevant generation and capacity statistics are given in Tables B.3.8 and B.3.9.

TABLE B.3.7
Projected Canadian Thermal Power Generation and Emissions

PROVINCE	GENERATION		EMISSIONS (METRIC TONNES x 1000)				REMARKS
	1990 GWh	2000 GWh	1990 SO_2	NO_x	2000 SO_2	NO_x	
Newfoundland	Nil	Nil	Nil		Nil		All hydro after 1989
Nova Scotia	6 445	9 160	79.4	19.9	87.1	21.2	
New Brunswick	4 840	4 950	83.1	18.6	88.9	18.9	
Prince Edward Island (via New Brunswick)	660	840	21.6	3.2	22.0	3.9	
Québec	0	0	Nil		Nil		All hydro
Ontario	41 570	55 870	390	60	260	40	
Manitoba	200	1 730	1.0	1.0	14.1	7.7	
Saskatchewan	5 910	10 620	12.2	13.6	27.8	26.4	
Alberta	30 910	48 790	62.2	72.3	90.4	110.3	
British Columbia	740	13 200	3.6	3.6	73.9	31.0	Mostly hydro until 1990

TABLE B.3.8
Capacity Additions By Province

Reference: 1979 - Electric Power Statistics, Vol. 1, Appendix A.

PROVINCE	DATE	TYPE	TOTAL ADDITION AND SUBTRACTIONS, MW	FUEL
Newfoundland	1982	Hydraulic	90 MW	-
	1984	Hydraulic	125 MW	-
Nova Scotia	1984	Thermal	150 MW	Coal
	1987	Thermal	150 MW	Coal
New Brunswick	1982	Nuclear	630 MW	-
	1985	Thermal	1 000 MW	Conversion (oil to coal)
Québec	1981	Hydraulic	2 000 MW	-
	1982	Hydraulic	1 600 MW	-
	1983	Hydraulic	1 600 MW	-
	1983	Hydraulic	685 MW	-
	1984	Hydraulic	2 600 MW	-
	1985	Hydraulic	1 600 MW	-
	1986	Hydraulic	1 050 MW	-
	1987	Hydraulic	1 160 MW	-
	1988	Hydraulic	880 MW	-
	1989	Hydraulic	1 650 MW	-
	1990	Hydraulic	560 MW	-
Ontario	1980	Thermal	(-600 MW)	(was gas)
	1981	Nuclear	500 MW	-
	1982	Nuclear	1 950 MW	-
	1983	Nuclear	1 750 MW	-
	1984	Nuclear	750 MW	-
	1987	Nuclear	750 MW	-
	1988	Thermal	200 MW	-
	1988	Nuclear	880 MW	-
	1989	Nuclear	1 760 MW	-
	1990	Nuclear	880 MW	-
Saskatchewan	1980	Thermal	300 MW	coal
	1981	Hydraulic	90 MW	-
	1982	Thermal	300 MW	lignite
	1986	Hydraulic	250 MW	-
	1987	Thermal	(-60 MW)	(was coal)
	1987	Thermal	(-90 MW)	(was gas)
	1987	Thermal	300 MW	lignite
	1988	Thermal	300 MW	lignite
	1990	Hydraulic	400 MW	-
	1990	Thermal	(-125 MW)	(was gas)

TABLE B.3.8 (continued)
Capacity Additions by Province

Reference: 1979 - Electric Power Statistics, Vol. 1, Appendix A.

PROVINCE	DATE	TYPE	TOTAL ADDITION AND SUBTRACTIONS, MW	FUEL
Alberta	1980	Thermal	350 MW	coal
	1981	Thermal	360 MW	coal
	1983	Thermal	375 MW	coal
	1984	Thermal	375 MW	coal
	1985	Thermal	200 MW	coal
	1986	Thermal	550 MW	coal
	1987	Thermal	375 MW	coal
	1989	Thermal	750 MW	coal
	1990	Hydraulic	360 MW	-
British Columbia	1980	Hydraulic	1 325 MW	-
	1983	Hydraulic	900 MW	-
	1984	Hydraulic	900 MW	-
	1988	Hydraulic	900 MW	-
	1988	Thermal	500 MW	lignite
	1989	Thermal	500 MW	lignite
	1989	Hydraulic	400 MW	-
	1990	Thermal	500 MW	lignite
	1991	Thermal	500 MW	lignite

TABLE B.3.9
Projected Generation Increases, Export/Import Balance

Province	Total Generation (all sources) 1980/1990	1990/2000	Net Imports/ Exports)
Newfoundland (gross including exports to Quebec)	1.0%	1.3%	Exports 38000 GWh constant
Nova Scotia	2.8%	2.8%	Imports 300 GWh constant
New Brunswick	5.4%	3.0%	Exports 1500 GWh '80 3000 GWh '90 3000 GWh '00
Prince Edward Island	1.1%	2.5%	0
Quebec	All hydro generation		Unrelated to emissions
Ontario	3.0%	3.0%	Exports 12000 GWh '80 20000 GWh '90 20000 GWh '00
Manitoba	1.5%	2.1%	Exports 5000 GWh '80 5000 GWh '90 3000 GWh '00
Saskatchewan	3.0%	3.2%	Imports 600 GWh constant
Alberta	4.9%	4.6%	Exports 300 GWh constant
British Columbia	3.8%	3.9%	Exports 600 GWh constant

NOTE: Exports to USA are either firm or interruptible. Major changes to exports are expected from New Brunswick - 50% of output of Point LePreau Nuclear Station after 1984 (i.e. half of 630 MW) - and from Ontario, 1 000 MW constant firm power increase above existing 1 200 MW from after 1984, for 10 years.

Non-utility Fuel Use

Non-utility fuel use includes residential, commercial and industrial fuel combustion. The projections of non-utility fuel use are based on the National Energy Program (NEP) announced by the Canadian government in 1980. The main objective of the NEP is to reduce oil consumption, mainly through the substitution of natural gas for oil-derived fuels. This is to be achieved by extension of the natural gas pipeline east of Montreal into Eastern Quebec and the Maritimes, and expansion of the areas already served. Secondly, financial incentives are being provided to encourage the switch of residential home heating from oil to gas or electricity. Finally, the NEP provides for a lower domestic cost for natural gas compared to oil to encourage users to convert to gas.

In developing the fuel forecast projections for these sectors, the following information sources were used:

1) Light Fuel Oil/Heavy Fuel Oil/Kerosene: projected consumption estimates of these fuels have been provided by the Department of Energy, Mines and Resources who also considered the fuel demand forecasts in the June 1981, NEB report on "Canadian Energy - Supply and Demand 1980 - 2000". Prices for energy sources are shown on page 23 of this report.

2) Natural Gas: projected consumption estimates of natural gas were taken from the June 1981, NEB report on "Canadian Energy - Supply and Demand 1980 - 2000".

3) Coal and Liquified Petroleum Gas: projected consumption estimates of these fuels was based on the assumption that the quantities would remain at current levels to year 2000.

4) The projected fuel consumption estimates were based on best estimates of fuel suppliers and the NEB. These estimates were not based on an econometric model which would select the cheapest fuel source. The sulphur contents of these fuels are shown in Table B.3.10 and the emission estimates in Tables B.3.11 to B.3.15.

5) Energy conservation was considered in the NEB projections.

6) Non-utility fuel use estimates for the three sectors were based on the NEB report and these requirement were converted into various fuel types by the Department of Energy, Mines and Resources.

7) The consumption forecasts for petroleum fuels and natural gas in the non-utility sector are shown in Table B.3.15. Should the conversion to gas or the upgrading of heavy fuel oil be delayed, the SO_2 emission forecasts would be too low.

TABLE B.3.10

Per cent (%) Sulfur Content of Fuel Products

FuelProduct/Year	1980 Ont.-west/ Que.-east[2]	1985 Ont.-west/ Que.-east[2]	1990 Ont.-west/ Que.-east[2]	2000 Ont.-west/ Que.-east[2]
Light Fuel Oil	0.3/0.5	0.4/0.6	0.5/0.6	0.3/0.4
Kerosene/Stove Oil	0.3/0.5	0.3/0.5	0.3/0.5	0.3/0.3
Heavy Fuel Oil	2.1/2.6	2.1/2.6	2.1/2.6	2.1/2.6
LPG	0.37/0.37	0.37/0.37	0.37/0.37	0.37/0.37
Coal[3]	0.6/2.5	0.6/2.5	0.6/2.5	0.6/2.5

[1] Fuels used in the province of Ontario and Western Canada

[2] Fuels used in the province of Quebec and Eastern Canada

[3] Exceptions: Ontario equals 2.5% sulfur
New Brunswick equals 7% sulfur

TABLE B.3.11

Non-utility Fuel Use
Residential/Commercial
Projected SO_2 Emissions (kilotonnes)

PROVINCE	1980	1985	1990	1995	2000
Newfoundland	6.9	4.9	2.9	1.7	0.9
Prince Edward Island	1.8	1.3	0.7	0.5	0.3
Nova Scotia	20.0	14.8	8.7	5.4	3.6
New Brunswick	10.7	7.7	4.5	2.5	1.3
Quebec	110.7	53.7	27.1	17.2	7.8
Ontario	45.1	27.7	21.1	14.4	5.3
Manitoba	2.3	2.0	2.1	1.7	1.5
Saskatchewan	1.8	1.6	1.6	1.3	1.0
Alberta	1.9	1.6	1.7	1.3	1.1
British Columbia	8.3	6.9	5.1	4.8	3.8
TOTAL CANADA	209.5	122.2	75.5	50.8	26.8

TABLE B.3.12

Non-Utility Fuel Use
Residential/Commercial
Projected NO_x Emissions (kilotonnes)

PROVINCE	1980	1985	1990	1995	2000
Newfoundland	1.9	1.2	0.7	0.5	0.4
Prince Edward Island	0.5	0.3	0.2	0.1	0.1
Nova Scotia	4.8	3.2	1.7	1.1	0.5
New Brunswick	2.8	1.8	1.1	0.7	0.5
Quebec	30.3	15.8	10.7	10.3	7.9
Ontario	31.1	24.8	22.7	15.8	21.9
Manitoba	3.1	3.2	3.2	3.2	3.6
Saskatchewan	3.1	3.9	4.3	4.6	5.2
Alberta	9.7	12.3	13.7	14.4	16.4
British Columbia	6.9	7.0	6.7	7.7	8.8
TOTAL CANADA	94.2	73.5	65.0	68.4	65.3

TABLE B.3.13

Non-Utility Fuel Use
Industrial
Projected SO_2 Emissions (kilotonnes)

PROVINCE	1980	1985	1990	1995	2000
Newfoundland	26.8	18.2	13.1	8.8	6.0
Prince Edward Island	0.5	0.4	0.3	0.2	0.2
Nova Scotia	50.2	28.5	30.2	24.0	19.2
New Brunswick	44.8	33.2	26.0	20.9	17.6
Quebec	245.1	177.8	135.7	100.3	81.9
Ontario	172.9	107.2	69.1	49.2	44.5
Manitoba	7.0	7.5	8.1	7.2	8.2
Saskatchewan	6.1	7.4	7.6	10.2	7.7
Alberta	14.4	16.5	17.6	16.4	19.5
British Columbia	48.6	34.6	25.5	24.7	22.9
TOTAL CANADA	616.4	441.3	333.2	261.9	227.7

TABLE B.3.14

Non-Utility Fuel Use
Industrial
Projected NO_x Emissions (kilotonnes)

PROVINCE	1980	1985	1990	1995	2000
Newfoundland	6.4	4.3	3.1	2.0	1.4
Prince Edward Island	0.2	0.2	0.1	0.1	0.1
Nova Scotia	10.4	8.1	7.3	7.3	7.2
New Brunswick	9.8	8.2	8.6	7.1	7.3
Quebec	63.4	49.4	42.3	35.8	33.6
Ontario	71.1	53.7	48.5	46.2	51.5
Manitoba	4.1	4.2	4.3	4.6	4.7
Saskatchewan	6.9	9.1	10.2	10.7	12.3
Alberta	106.1	141.0	158.4	168.4	193.3
British Columbia	21.8	19.9	18.1	20.6	22.8
TOTAL CANADA	300.2	298.1	300.9	302.8	334.2

TABLE B.3.15

Consumption Forecast Non-Utility Fuels

	1980	1985	1990	1995	2000
Petroleum Products[1] (Megalitres/year)					
Residential					
Light Fuel Oil	11 700	6 620	4 990	3 890	2 610
Heavy Fuel Oil	380	170	120	6	----
Commercial					
Light Fuel Oil	3 680	2 380	1 510	810	4 380
Heavy Fuel Oil	1 800	700	120	60	360
Industrial					
Light Fuel Oil	1 335	870	810	700	700
Heavy Fuel Oil	10 795	4 990	3 130	2 090	1 570
Natural Gas (Gigalitres/year)					
Residential	10 410		13 560		14 930
Commercial	8 990		14 020		17 890
Industrial	25 965		29 140		41 900
Liquified Petroleum Gas (Megalitres/year)					
Residential	1 120	1 120	1 120	1 120	1 120
Commercial	----	----	----	----	----
Industrial	1 120	1 120	1 120	1 120	1 120
Coal (Kilotonnes)					
Residential	140	140	140	140	140
Commercial	54	54	54	54	54
Industrial	1 594	1 594	1 594	1 594	1 594

NOTE: This forecast assumes that NEB June 1981 forecasts are adjusted to NEP plans which will result in:

a) upgrading of heavy fuel oils;
b) conversion from petroleum fuels to natural gas use.

[1] Diesel fuel oil consumption from all sectors of the Canadian economy has been considered under the transportation sector.

Industrial Processes

This section describes the industrial processes in Canada which are significant emitters of SO_2.

i) Petroleum Refineries

Emission forecasts from the petroleum refining sector have been based on questionnaire data from the industry in 1974 and increased for current crude oil processing capacity. These are process emissions. The associated emissions from refinery fuel combustion are included in the industrial fuel category.

Refinery process emission forecasts for 1985, 1990, 1995 and 2000 were based on 1980 estimates and provided for quantity and type of crude processed. The emission projections are given in Table B.3.16.

ii) Natural Gas Processing

Approximately half of the gas found to date in Canada contains significant quantities of hydrogen sulfide. In order to meet pipeline specifications, this "sour" gas must be processed to remove the poisonous sulfur compounds. These compounds are converted into sulfur at an average recovery efficiency of 97 percent. The unrecovered sulfur compounds are flared or incinerated, and emitted to the atmosphere as SO_2.

Alberta is the major natural gas producing province in Canada. The projected emission estimates for natural gas processing in Alberta were taken from the report "Sulfur Emissions - Alberta Energy Industries, October 1979", prepared by Alberta's Resources Conservation Board (ERCB). The estimates are based on the assumption that marketable gas production, currently at over 56.6 million cubic meters per year, is expected to increase further to about 87.7 million cubic meters per year in the mid 1980's and then decline gradually to 62.3 million cubic meters per year by the end of the century. In the period 1988 to 1995, production is expected to decline as exports diminish, then increase with Canadian demand before commencing a decline due to falling pressures in the gas reservoirs.

The forecast of future sulfur dioxide emissions assumes that the average sulfur content to gas ratio of 106 tonnes per million cubic meters experienced in the 1958 to 1978 period will continue. Having regard for recent trends in sour gas production and towards the connection of more sweet than sour gas, and also the long range prospect that sweet or low sulfur gas may predominate in reserve additions, the forecast may overstate future emissions.

With few exceptions, current Alberta requirements for sulfur recovery at gas plants range from a minimum of 92 to 93 percent for small plants (10 to 100 tonnes per day of inlet sulfur) to 98 to 99 percent for large plants (with inlet sulfur exceeding 1000 tonnes per day). These recovery levels must be achieved on a quarterly basis and are assumed to remain in force during the forecast period.

British Columbia also produces natural gas, and its emissions have been assumed to remain constant to the end of the century. Any increase of emissions from new sources would be minor because new plants must recover 99 percent of the sulfur.

Table B.3.17 shows the emissions of SO_2 from natural gas processing to the year 2000 in Canada.

iii) Tar Sands Operations

The oil sands deposits of northern Alberta contain crude bitumen, a heavy viscous hydrocarbon which will not flow at prevailing reservoir temperatures. Crude bitumen, which contains an average of about 5 weight percent sulfur, is extracted from strip mined oil sands or, at depth, can be recovered through wells using thermal or other recovery techniques. The recovered crude bitumen is processed in an upgrading plant to produce "synthetic crude oil", which is essentially sulfur free.

The projected emission estimates for tar sands operations in Alberta have been taken from the report "Sulfur Emissions - Alberta Energy Industries, October 1979", prepared by the ERCB. The estimates are based on the following schedule of projected oil sands and heavy oil projects shown in Table B.3.19. On the assumption that these projects will be completed as proposed, the ERCB predicts that annual synthetic crude oil production will increase to about 14 million cubic meters by 1985 (currently about 8 million cubic meters), 32 million cubic meters by 1987 and 75 million cubic meters by the year 2000.

Table B.3.18 shows the emissions of SO_2 from the tar sands operations in Alberta to the end of the century.

iv) Emissions from Other Sources

As described in Appendix 2 on the methodology for the 1980 SO_2 and NO_x inventory, the emissions from other industrial sectors and miscellaneous sources do not contribute significantly to the overall inventories and it is not expected that this situation will change. No attempt has been made to develop projections for these sources to the end of the century; emissions have been assumed to remain constant.

Transportation

In arriving at the projected totals for the emissions of NO_x for the transportation sector (Table B.3.20), emissions from gasoline powered road vehicles were calculated assuming no change in emission standards, tampering rates, speed distribution or vehicle age distribution. The vehicle-miles travelled were assumed to grow linearly but at a rate which equalled the 20 year growth at an annual rate of 2.6 percent. The non-road vehicles and all diesel-powered vehicles were assumed to be subject to no further regulations and to increase total fuel consumed by 2.8 percent by 1990 and 2.3 percent thereafter.

In Table B.3.21, the projected total emissions at each 5 year point have been prorated by current population to the fifteen source regions in Canada for the convenience of modelers.

In Table B.3.22, the fleet emission factors for each category of gasoline powered road vehicles is shown for each calendar year targeted. The emission factors for heavy duty diesel are not shown because their emissions are calculated on fuel consumed rather than per mile travelled.

TABLE B.3.16

Petroleum Refining[1] Projected SO_2 Emissions (kilotonnes)

PROVINCE	1980	1985	1990	1995	2000
Newfoundland	----	----	----	----	----
Prince Edward Island	----	----	----	----	----
Nova Scotia	10.2	8.0	6.8	6.7	6.9
New Brunswick	5.5	4.3	3.7	3.6	3.7
Quebec	23.9	21.3	20.2	19.8	19.9
Ontario	32.7	30.1	43.5	30.2	31.7
Manitoba	2.2	2.6	2.9	2.7	3.5
Saskatchewan	1.7	2.0	2.3	2.2	2.8
Alberta	3.2	3.8	4.2	3.9	5.1
British Columbia	10.0	9.9	9.9	10.6	11.3
TOTAL CANADA	89.4	82.0	93.5	79.7	84.9

[1] The emission estimates represent process emissions only.

Table B.3.17

SO_2 Emissions from Natural Gas[1] Processing (Kilotonnes)

PROVINCE	1985	1990	1995	2000
Alberta	473.5	422.7	390.1	343.4
British Columbia	41.7	41.7	41.7	41.7
CANADA TOTAL	514.2	464.4	431.8	385.1

[1] The NEP will not significantly alter these projections.

TABLE B.3.18

SO_2 Emissions from Tar Sands Operations (Kilotonnes)[1]

PROVINCE				
Alberta	183	285	366	325
CANADA TOTAL	183	285	366	325

[1] The NEP will not significantly alter these projections.

Table B.3.19

Schedule of Oil Sands and Heavy Oil Projects

Year[a]	Area	Type	Production Capacity/ cubic meters per day
1967	Athabasca	Surface	7 155
1978	Athabasca	Surface	20 510
1982	Athabasca	Surface	3 180
1984	Athabasca	Surface	10 490
1986	Cold Lake	In Situ	22 260
1986	Athabasca	Surface	22 260
1990	Athabasca	In Situ	33 385
1993	Athabasca	Surface	33 385
1996	Cold Lake or Lloydminster	In Situ	29 410
1997[b]	Athabasca	Surface	(10 335)
1999	Athabasca	Surface	33 385

[a] year of start-up

[b] year of shut-down of SUNCOR project

Table B.3.20

Transportation
Projected NO_x Emissions (Kilotonnes)

Year	On-Road Gasoline Powered Vehicles	Other Transportation Sources	Total Canada
1980	540.0	574.4	1 114.4
1985	537.0	659.0	1 196.0
1990	584.0	756.6	1 340.6
1995	651.0	847.6	1 498.6
2000	718.0	949.7	1 667.7

TABLE B.3.22

Fleet Emission Factors for Gasoline Powered Vehicles

Type	Emission Standard	Fleet Emission Factors (g/mile)				
		1980	1985	1990	1995	2000
LDGV	3.1 g/mile(1)	2.76	2.26	2.17	2.17	2.17
LDGT	3.1 g/mile(1)	2.46	2.28	2.24	2.24	2.24
MDT	optional[1,2]	5.04	5.04	5.04	5.04	5.04
HDGT	HC + NO_x = 16g/bhp/hr(1)	10.1	10.1	10.1	10.1	10.1

NOTES:

1. Many Canadian vehicles are identical to U.S. models and thus are designed for U.S. standards.
2. The manufacturer has the option of certifying engines as light or heavy duty.

TABLE B.3.21

Transportation
Projected NO_x Emissions by Province
(kilotonnes)

PROVINCE	YEAR 1980	1985	1990	1995	2000
Newfoundland	18.8	20.1	22.6	25.2	28.1
Prince Edward Island	5.1	5.5	6.1	6.9	7.6
Nova Scotia	32.5	34.8	39.1	43.6	48.6
New Brunswick	27.6	29.6	33.2	37.1	41.3
Quebec	221.2	237.4	266.1	297.5	331.0
Ontario	324.7	348.5	390.7	436.7	486.0
Manitoba	65.5	70.3	78.7	88.0	98.0
Saskatchewan	95.7	102.7	115.0	128.6	143.1
Alberta	181.0	194.3	217.8	243.5	271.0
British Columbia	142.4	152.9	171.3	191.5	213.2
TOTAL CANADA	1 114.5	1 196.1	1 340.6	1 498.6	1 667.8

C. EMISSION SOURCE SECTORS

The industry sectors described in this chapter are major sources of SO_x and NO_x. The control technologies that are either currently available or will be in the near future are highlighted. The emission sources discussed are thermal power plants (fossil fuels), non-ferrous smelters, mobile sources (transportation), pulp and paper, petroleum refining, industrial, residential and commercial fuel combustion and incinerators.

Each sector is described in terms of the production processes and capacities and the attendant SO_x and NO_x emissions. This is followed by discussions of the control technologies in use, available or emerging for each industry sector. The control technologies are analyzed in terms of performance, cost, applicability, technical uncertainty and associated problems. Alternative production processes are also discussed where applicable.

C.1 FOSSIL FUEL-FIRED GENERATION PROCESSES

C.1.1 Description

The Canadian Sector

Canada's electrical generating capacity is expected to double between 1980 and 2000 (1). This expansion will be noticeable in all three major types of generation: hydroelectric, nuclear, and conventional thermal. Hydroelectric power will double, maintaining its leading role in the utility sector, nuclear power will grow by a factor of three to four, while thermal generation will increase to a somewhat lesser degree, by about 90%.

Conventional steam-electric capacity, at 27 500 megawatts (MW) in 1980, is expected to increase to approximately 52 400 megawatts by the year 2000 (1). All announced steam-unit additions by 1990 will be coal-fired. This added coal-burning capacity will cause annual coal consumption to increase, from about 25 000 kilotonnes in 1979 to approximately 55 000 kilotonnes in 1990 and about 85 000 kilotonnes in 2000. The majority of the steam-unit additions will be located in the provinces of Alberta and British Columbia.

Table C.1.1 shows the Canadian generation of electrical energy by the utilities according to energy source for 1980. In Table C.1.2 the generation mix for fossil-fuel fired utility plants is presented by province for the year 1980.

TABLE C.1.1

CANADA

Electric Utility Generation By Energy Source (1980)

Energy Source	Net Generation GW.h	% of Total Generation
Coal	56 500	17.2
Petroleum	10 500	3.2
Natural Gas	5 300	1.6
Hydro	220 500	67.1
Nuclear	35 900	10.9
Geothermal and Other	0	0
Total	328 700	100.0

TABLE C.1.2

Summary of Capacity and Generation for Fossil-Fuel-Fired Utility Plants by Province, 1980

PROVINCE	Fossil Generation		Percent Supplied by Fuel Type		
	Capacity (MW)	Net Generation (GW.h)	Coal	Oil	Gas
Newfoundland	692	1 460	0	100	0
P.E.I.	112	130	0	100	0
Nova Scotia	1 603	5 510	46	54	0
New Brunswick	1 896	5 960	12	88	0
Quebec	1 120	120	0	100	0
Ontario	12 486	31 330	98	NEG	2
Manitoba	469	280	82	18	NEG
Saskatchewan	1 696	6 330	91	NEG	9
Alberta	4 810	20 210	81	NEG	19
British Columbia	1 666	790	0	13	87
Yukon & N.W.T.	102	220	0	100	0
Canada Total	26 552	72 290	78	15	7

Source: Statistics Canada, Preliminary Electric Power Statistics (1980)

The U.S. Sector

Electric utility generation in the U.S. by energy source is summarized for the year 1980 in Table C.1.3. Roughly 50 per cent of the electricity generated in 1980 was supplied by coal-fired units. The remaining 50 percent was supplied by oil, natural gas, hydro and nuclear units in rougly equal proportions. Total U.S. electric generation in 1980 was 2 286 billion kilowatt-hours, an increase of roughly 2 percent over the preceding year (1).

TABLE C.1.3

U.S. Electric Utility Generation by Energy Source (1980)

Energy Source	Generation GW.h	% of Total Generation
Coal	1 162 000	50.8
Petroleum	246 000	10.8
Natural Gas	346 000	15.1
Hydro	251 000	11.0
Nuclear	276 000	12.1
Geothermal and Other[1]	6 000	0.2
Total	2 286 000	

Source: Reference 2.

[1] includes production from plants that consume wood, refuse, and other vegetable fuels.

Production of electricity by coal-fired units in the U.S. has been steadily increasing since 1960 (with the exception of 1978, when coal use was roughly 1 percent less than in 1977) and has more than doubled since 1964 (2). The total amount of coal delivered to electric utility plants in the first six months of 1980 was 295.4 million tons (2). Over 60 per cent of this coal went to 11 states: Ohio (26.1)*, Texas (22.0), Pennsylvania (20.9), Illinois (19.1), Indiana (18.2), West Virginia (15.4), Tennessee (13.2), Kentucky (12.0), North Carolina (11.2), Michigan (11.1) and Missouri (10.8)(3). Coal use in the U.S. utility sector is expected to increase over the next few years.

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* Numbers in brackets are million tons delivered to utility plants in each state.

Utility Generation by Region

U.S. utility capacity and generating rate for fossil-fuel-fired power plants in 1980 is summarized by region in Table C.1.4., as is the percentage generation by fuel. From this table it is evident that the greatest quantities of coal used in the utility sector are in the following regions (in decreasing order): east north central, south Atlantic, west south central, middle Atlantic and west north central states. U.S. totals listed at the bottom of Table C.1.4 show that coal constitutes 66 percent of total electric generation in fossil-fuel-fired plants (4).

Electric generation by fossil fuel plants is broken down by state and region in Table C.1.4 for areas of the country close to the U.S./Canadian border. The greatest use of coal fired electric generation occurs in the following states*: Ohio (103.2), Pennsylvania (83.2), Illinois (63.4), and Indiana (59.5)(4). In each of these states, coal accounted for more than 80 percent of the electricity generated in 1978.

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* The numbers in brackets are thousand megawatt-hours of coal-fired electric generation.

TABLE C.1.4

Summary of Capacity and Generation for Fossil-Fuel-Fired Plants by Region, 1980

	Fossil Generation		Percent Supplied by Fuel Type		
Region	Capacity (MW)	Net Generation (GW.h)	Coal	Oil	Gas
New England	3 544	12 558	9	90	1
Mid-Atlantic	48 425	191 203	13	66	21
East North Central	85 658	334 998	95	4	1
West North Central	34 558	136 083	91	1	8
South Atlantic	77 111	327 158	75	20	5
East South Central	38 738	168 536	93	2	5
West South Central	76 140	293 400	8	53	39
Mountain	24 185	121 024	85	2	13
Pacific	26 060	100 209	8	40	52
United States Total	424 524	1 730 982	66	14	20

Source: Energy Information Administration, "Energy Data Report: Power Production, Fuel Consumption, and Installed Capacity Data 1980 Annual", DOE/EPA-0049 (80)

REFERENCES

1. "Electric Power in Canada 1980", Department of Energy, Mines and Resources, Energy Policy Sector.

2. National Electric Reliability Council, "Electric Power Supply and Demand: 1981-1990", July 1981, includes 1980 actual generation.

3. DOE's Energy Information Administration, "Energy Data Report: Coal Distribution, January-June 1980", Report No. DOE/EIA-0125(80/2Q), October 20, 1980.

4. TVA - "Technical Review of Dry Scrubbers and Economic Evaluation of Spray Dryer", 2/81 EPA 600/7-81-014

C.1.2 Emissions and Control Technologies

In general, the optimum process for controlling a given pollutant depends on the degree of control required and the cost of the control. Processes that provide maximum reductions in emissions are quite expensive and are usually not implemented unless the high efficiency is considered to be essential. On the other hand, removal techniques that are less expensive are not normally capable of a high degree of control. As the emphasis in controlling emissions from fossil fuel-fired power plants is expanding from local to regional considerations, a more detailed assessment of abatement methods is needed.

Pollutants emitted from fossil-fuel-fired plants include sulfur oxides (SO_2 and SO_3), nitrogen oxides (NO and NO_2, generally referred to as NO_x), and solid material carried with the gas stream (ash from the fuel, unburned carbon, and other non-gaseous particles--all generally referred to as "particulate matter"). Most of these come from the fuel itself, by reaction of sulfur and nitrogen compounds with oxygen supplied by the combustion air, and by burning out the combustible compounds leaving the ash as small solid particles. In addition, some NO_x is formed by reaction of nitrogen and oxygen in the combustion air.

The amounts of such pollutants vary with type of fuel, design and size of boiler, and capacity factor. Typical data are given in Table C.1.5 for an uncontrolled 500 MW unit. Although the tonnages listed are high, the concentrations in the flue gas are quite low because of the very large flue gas volume, which is composed mainly of carbon dioxide and water vapor. For example, the 500 MW boiler in Table C.1.5 would produce about 60,000 tons of flue gas per day, at full power; at 60% capacity factor, this is equivalent to 13 million tons of flue gas per year.

The main regulatory emphasis in the past has been on particulate matter, where coal is the fuel, because of the large quantities emitted. Devices that collect and remove particulates from the gas stream have been required for a long time. Since 1971, sulfur oxide and nitrogen oxide emissions have been federally regulated in the U.S. In Canada, federal guidelines have been promulgated for new thermal power plants and over the past decade provinces have also put into place regulations for these sources.

TABLE C.1.5

Typical Uncontrolled Emissions of Pollutants[a]

Pollutant (tons per year)

Fuels	Sulfur oxides	Nitrogen oxides	Particulate Matter
Natural gas	--[b]	4 000	--[b]
Oil (1.0% sulfur)	15 000	4 800	1 100
Coal			
Low-sulfur (0.7%)	15 000	8 200	110 000
High-sulfur (4.0%)	88 000	8 200	110 000

[a] 500 MW boiler, 60% load factor. Levels given are fairly typical; in practice they vary over a wide range. Coal burned, about 1.1 million tons/year.

[b] Natural gas normally contains very little sulfur or ash.

Sulfur oxides and particulates are removed from the gas stream by a variety of devices. (Emissions can also be reduced by using low-sulfur and/or low ash fuels.) Coal preparation techniques can improve the quality of coal as a fuel, and can lead to reduced SO_2 and particulate matter emissions. For nitrogen oxides, the general practice has been to reduce emissions by altering combustion conditions in the boiler in such a way as to reduce NO_x formation. Since typical emission reductions are about 30%, there has been some use in Japan of flue gas cleaning devices to remove NO_x from the gas.

Emission Rates

In this sector, emission rates are routinely stated in terms relating to the heat input to the boilers. The range of emissions for the three pollutants varies widely, depending on the fuel characteristics and the boiler design. Uncontrolled emissions can be as high as the following:

SO_2	Canada	up to 13 lb/10^6 Btu
	U.S.	up to 8 lb/10^6 Btu
NO_x	Canada/U.S.	up to 1.3 lb/10^6 Btu
Particulates	Canada/U.S.	up to 6 lb/10^6 Btu

Definitions

"In use" technologies are those which have been demonstrated on a commercial scale and for which orders have subsequently been placed.

"Available" technologies are those which have been demonstrated but not yet installed or ordered to any significant extent.

"Emerging" technologies are those in the research and development stages which have been developed to the pilot-scale level.

A list of the "in use", "available" and "emerging" control technologies is given below, along with alternate generation processes which may become available. Further detail is given on in-use and available technologies as these are the technologies seen to be applicable within the foreseeable future. Additional details on selected processes are presented in Appendix 5.

Summary of Technologies

In Use Technologies

SO_2 Reduction

1) Fuel substitution
2) Physical coal cleaning
3) Blending with low-sulfur fuel
4) Oil desulfurization
5) Wet FGD throwaway processes (lime/limestone, dual alkali, alkaline fly ash)
6) Dry FGD throwaway process (spray dryer FGD)
7) Regenerable FGD processes (Wellman-Lord, Mag Ox)

NO_x Reduction

1) Flue gas recirculation (FGR) (gas-fired utilities)
2) Low excess air
3) Staged combustion

Available Technologies

SO_2 Reduction

1) Lime/limestone scrubbing with chemical additives e.g., adipic acid

NO_x Reduction

1) Low-NO_x burners
2) Flue gas treatment (FGT)

Emerging Technologies

SO_2 Reduction

1) Atmospheric fluidized bed combustion
2) Pressurized fluidized-bed combustion
3) Fuel gasification
4) Gasification with combined cycle operation
5) Coal liquefaction, direct (SRC-I and SRC-II) and indirect (e.g., SASOL)
6) Limestone injection with multi-stage burner, (LIMB process)

NO_x Reduction

1) Flue gas treatment (FGT)
2) Advanced low-NO_x burners

Advanced low-NO_x coal burners, projected to be capable of NO_x emission of 0.2-0.3 lb per million Btu, have begun commercial demonstration. It is projected that these advanced low-NO_x burners may be commercially available in the 1983-85 period.

FGT processes have been evaluated for coal application at pilot scale in Japan and the U.S., and show that the long-term NO_x removal may be affected by the nature of the fly ash. More effort to evaluate the impact of coal and fly ash type on FGT processes is needed.

C.1.2.1 Sulfur Dioxide Control Technologies

In the past, the main approach to sulfur oxide control in countries such as Japan, Canada and the U.S. has been the use of naturally occurring low-sulfur fuel. This is still the practice in Japan and Canada, but in the U.S. 1978 federal regulations require a reduction in uncontrolled emissions for all new utility boilers burning oil or coal. Several approaches can be used to attain the reduction, including fuel blending, fuel desulfurization, coal cleaning, coal conversion, desulfurization during combustion, and FGD.

i) Fuel Substitution

ii) Physical Coal Cleaning

Some of the sulfur in coal can be removed at relatively low cost by physical cleaning methods; that is, the coal is crushed and subjected to treatment based on density differences to separate the fractions. Since the more dense fractions contain much of the sulfur, some 10-30% of the sulfur can be removed depending on the characteristics, among other things. A variety of methods are used widely in the U.S., including washing, shaking, and mineral concentration methods.

If more than 10-30% removal of the sulfur is required, physical cleaning becomes expensive. It can be combined with other methods to advantage if an intermediate degree of removal is acceptable and if the original pyrite sulfur content is extremely high. For 90% and higher removal of sulfur in the fuel, (10% or less left in the coal), as now required for new plants in the U.S. other methods are more cost effective.

A Tennessee Valley Authority (TVA) study shows a cost of $0.22 per lb of sulfur removed for cleaning and $0.237 per lb for limestone scrubbing (2 000 MW, 3.5% S coal, 29-32% removal by cleaning, and 85% by FGD). Within the limits of accuracy of the estimates, the costs are thus about the same. Physical coal cleaning has some additional benefits such as ash removal, higher Btu value and reduced transportation costs, which could influence the choice when 10-30% sulfur removal is acceptable (2).

For lower-sulfur coal, the cost of cleaning increases rapidly with decreases in coal sulfur content. For example, at 0.7% sulfur, the cost per lb of sulfur removed is $1.88, as compared to $0.89 for FGD, and at very low sulfur contents one reaches a point of economic impracticality (2).

iii) Chemical Desulfurization of Coal

Types of chemical desulfurization vary widely, from simple leaching to dissolution and reconstitution of the solids. One process, Solvent Refined Coal (SRC), cleans the coal to produce a a solid fuel.

There is as yet no commercial Chemical Coal Cleaning (CCC) process in operation, but there is a large U.S. pilot plant making SRC. Other CCC methods are only at the bench or pilot scale stage of development.

Chemical coal cleaning can attain a high degree of sulfur removal, but at high costs and energy losses. Overall removal of sulfur is in the range of 60 to 75%. SRC does better because of hydrogenation; the process probably can achieve up to 85% removal at a cost competitive with wet scrubbing.

Because of the chemical steps involved, chemical cleaning is considerably more expensive than physical cleaning. TVA estimates range from $0.253 to $0.44 per lb of sulfur removed. In contrast, the TVA estimated cost for FGD, (85% SO_2 removal compared to 59 to 73% for CCC), is $0.237 per lb of sulfur (2).

Various cost estimates have been published for SRC. EPRI indicates a cost of about $4.50 per million Btu for SRC, which corresponds to about $113 per ton of Eastern coal (at 12,500 Btu/lb). Raw coal plus scrubbing costs $25 to $30 per ton for the coal and $10 to $15 per ton for the scrubbing. However, SRC has several advantages that give other savings, e.g., ash reduction, thus making the cost comparison complicated. The process does not seem to be competitive with flue gas scrubbing at 90% and higher removal.

The cost comparison between CCC and FGD is markedly affected by reliability. CCC can be considered to have 100 percent reliability on the basis that the CCC plant will maintain a stockpile. For FGD, however, 100 percent reliability has not been generally attained.

iv) Desulfurization of Oil

Oil desulfurization is a well-developed technology, used widely in several countries. The method has been used extensively in Japan to reduce SO_2 emissions.

The residual sulfur in the treated oil is usually in the order of 0.2% to 0.5% but a higher degree of desulfurization is feasible. The situation is similar to coal cleaning in that the cost increases with the degree of desulfurization. Japanese data show an increase from $16/kL to $27/kL when increasing from 70% to 97% sulfur removal, compared to an equivalent increase from $16/KL to $19/KL for a similar improvement in efficiency for FGD (2).

v) Flue Gas Desulfurization - Dry Processes

One of the newer FGD developments is injection of a lime slurry into a spray-dryer concurrently with the flue gas. The lime reacts with the SO_2 to form a dry, solid product which is subsequently collected in an electrostatic precipitator (ESP) or fabric filter. The main advantages are relative simplicity of equipment, production of a dry waste, lower energy requirement, no reheat requirement, and possibly lower maintenance, and greater reliability. The drawbacks are the greater cost for lime (compared to limestone in wet FGD) and a relatively high stoichiometry to achieve a sufficient degree of sulfur removal from high sulfur coal. Thus, it is presently limited to Western low sulphur coal.

Only a limited amount of full-scale module data have been obtained on the spray dryer FGD process to date but utilities had contracted for 11 installations using low sulfur coal in the U.S. as of mid-1981. The initial capital cost advantage projections for dry FGD have recently narrowed compared to wet FGD.

TVA studies (1980) have indicated $154-158/kW for dry scrubbing capital costs on low sulfur Western coal (0.7% sulfur, 9 700 Btu/lb) compared to $176/kW for wet scrubbing. For high-sulfur Eastern coal, (3.5% sulfur, 11 700 Btu/lb) the respective costs for the same two processes are given as $200/kW and $243/kW. Annual revenue requirements for dry scrubbing on low sulfur Western coal are estimated in the same study to be 9.4-10.2 mills/kWh, and for wet scrubbing on the same fuel, they are 10.7 mills/kWh. For high-sulfur Eastern coal, the report gave a cost of 17.1 mills/kWh on dry scrubbing; using wet scrubbing the same coal requires 16.4 mills/kWh. The plant size is assumed to be a new 500 MW unit operating at 63% lifetime capacity factor; costs for retrofits, smaller units, and lower capacity factors, would be higher (1).

Operating cost advantage depends mainly on operating labor and maintenance, the amount of lime required and the price margin over limestone and the energy used. TVA estimates show lower direct costs (including absorbent) for wet scrubbing but overhead and capital charges may be less for dry processes.

vi) Flue Gas Desulfurization - Wet Scrubbing

Scrubbing the flue gas with limestone slurry is the basic FGD process, available commercially for over 10 years; lime has some operating advantages over limestone and is sometimes used. The main drawbacks of FGD processes have been corrosion/erosion, scaling and plugging in the absorber, unreliability of the slurry recirculation pumps, and production of a wet, difficult-to-handle sludge. There has been some trouble with system availability (hours on-line as a fraction of hours in a year less hours planned for maintenance), particularly with high-sulfur coal.

The problems in some plants are still not completely resolved. Reliability is being improved with spare modules. Small amounts of magnesium oxide or adipic acid have been found to be effective in raising SO_2 removal efficiency. At Springfield, Missouri, a 194 MW limestone FGD facility, removal efficiency has increased from 60% to 85% by adding 1000-1500 ppm of adipic acid. Limestone utilization and system reliability have improved significantly.

In the U.S., the current FGD capacity on utility boilers is over 34 000 MW and 72 000 MW more is under construction or planned. It is estimated that nearly 108,000 MW will be in operation by 1999 in the U.S. None are currently in use in Canada, but by 1990 two are planned on boilers of 500 MW each.

One of the wet scrubbing variations is the "dual alkali" process. The advantages are very high removal efficiency and more reliable operation.

Waste disposal options must be closely examined when considering wet scrubbing processes. Lime and limestone scrubbing produces solid waste in large quantities (mainly calcium sulfite or sulfate) with undesirable properties -- difficult to dewater and incapable of supporting weight.

Dewatering and compressive strength of the scrubber waste can be improved by forced oxidation which oxidizes calcium sulfite to calcium sulfate, a material which precipitates as large crystals with better settling characteristics. There is a trend to specifying forced oxidation. Another method of improving the waste solids properties is by fixation with lime and fly ash.

While the problem is not yet well-defined, the potential for leaching to occur is cause for concern. EPA is conducting a study to define the leaching characteristics at FGD waste disposal sites. Calcium sulfite and sulfate are innocuous, but there is concern about the leaching of metal compounds (selenium, arsenic, mercury, and others) from the fly ash collected in some scrubbers. FGD waste is currently exempt from the U.S. hazardous waste regulations.

vii) Flue Gas Desulfurization - Regenerable Processes

Recovery of the SO_2 from power plant flue gases, as a useful material using a regenerable FGD process, has long been a research goal. Various agencies, companies and institutes have also taken part, including TVA, EPA, DOE, and EPRI in the U.S., Bergbau Forschung in Germany, and various groups in Japan.

The results have not been promising primarily due to process economics, which currently favor the throwaway processes. In Japan there are only four regenerable FGD installations on utility boilers, totalling a little over 500 MW. There are also about 25 industrial units of 2 500 MW capacity. In the U.S., there are now eight operational regenerable FGD systems controlling about 1 600 MW of electric generating capacity.

There are a number of regenerable FGD processes under development. Only the more significant ones will be summarized.

- Wellman-Lord. This process can be considered an "in-use" technology. The gas is scrubbed with sodium sulfite solution and the resulting sodium sulfite-bisulfite solution heated to evolve a rich stream of SO_2, convertible either to sulfuric acid or elemental sulfur. It is used by the New Mexico Public Service and the Northern Illinois Public Service Company in the U.S., and by Chubu Electric in Japan.

- Chemico, United Engineers. This process has had extensive development and can be considered in the "available" category. The flue gas is scrubbed with a slurry of $Mg(OH)_2$ to precipitate $MgSO_3$. The sulfite is dried, calcined to evolve a rich stream of SO_2, and the SO_2 converted to sulfuric acid or elemental sulfur. Philadelphia Electic is installing the process at two stations, and has already operated the process at the Eddystone station.

- Rockwell. Sodium sulfite produced in a sodium carbonate absorbant-based spray drying process is reduced to sodium sulfide in a furnace and the resulting melt treated with water and carbon dioxide to evolve a rich stream of H_2S, convertible to sulfur by the Claus process. It is expected that coal can be used as a reducing agent - other methods require petroleum coke, natural gas, or expensive activated carbon. The process will be tested in a 100 MW facility at Niagara Mohawk's Huntley Station.

A major drawback of regenerable processes is their relatively high cost. Process complexity, high capital investment, and high energy requirements on some processes contribute to this. The need to find markets for the by-products, and the lack of experience on commercial installations have combined to lessen utility interest.

The energy input required for wet scrubbing processes is as follows (2);

Process	Energy requirement, % of boiler energy input with no control
Wellman-Lord (sulfur as product)	12-25
Magnesia scrubbing	5-10
Limestone scrubbing	1.5-3

viii) Process Choice

A ranking is provided in the following table for process choice at different required levels of emission reduction. It should be noted that this is only approximate and that site-specific conditions could well change the ranking. The ranking within each performance range is based on a subjective evaluation of factors such as cost, commercial viability, control efficiency, and process reliability.

Removal Efficiency level, %	Process Listing
Higher than 90%	1. Limestone scrubbing with additives 2. Lime scrubbing 3. Dual Alkali scrubbing 4. Regenerable FGD processes
50-90%	1. Limestone scrubbing, (with physical coal cleaning where upper limit on SO_2 emissions applies) 2. Chemical coal cleaning[a] 3. Low-sulfur fuel substitution 4. Limestone injection through multistage burner[a]
50-90% (low-sulfur coal)	1. Lime spray dryer process 2. Limestone scrubbing
Below 50%	1. Physical coal cleaning (highly variable effectiveness due to coal properties) 2. Blending with low-sulfur coal

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[a] Not yet commercialized

C.1.2.2 Nitrogen Oxide (NO_x) Control Technologies

The alternatives for NO_x control are boiler operation changes and combustion equipment modifications to reduce NO_x formation during combustion FGT to remove NO_x from the flue gas. Boiler operation changes achieve only modest NO_x reduction and may cause operational problems if not properly implemented. Combustion equipment modification is much less expensive than FGT, and is used in the U.S. and Japan. Where regulations have become so stringent that combustion modification can not achieve the required reduction, flue gas treatment is employed. It has been used on full-scale Japanese oil-fired and coal-fired units (4), and is being evaluated at a pilot scale on coal-fired boilers in the U.S.

i) Combustion Modifications

In the U.S. and Canada, combustion modification (CM) is the most common method of NO_x control. NO_x emissions can be decreased by providing the combustion air in stages, normally reducing air flow to the burner and admitting the remainder through "overfire" air ports. "Low-NO_x" burners that accomplish staged conditions within the burner flame have also been developed.

Staged combustion is a cost effective method of NO_x control but normally only reduces emissions by about 30%. Gas recirculation is more expensive but is effective for gas or light oil fired boilers, giving an emission reduction up to 50%. Low-NO_x burners are effective with gas recirculation. Combustion modification is reported to have given very low NO_x emissions in Japanese tests, 100 ppm with coal and 50 ppm with oil - a reduction of 75 to 80% compared to uncontrolled emissions. However, an advanced degree of combustion modification can cause slagging in the boiler and corrosion of heat transfer surfaces (5).

Typical emission limits achievable using combustion modification techniques and their associated capital costs are: (5)

Low Excess Air	0.9 lb $NO_x/10^6$ Btu, zero cost
Staged Combustion	0.7 lb $NO_x/10^6$ Btu, \$2-3/kW
Low-NO_x Burner	0.4-0.5 lb $NO_x/10^6$ Btu, \$2-\$10/KW

Emissions are based on coal-fired units emitting 1.0 lb $NO_x/10^6$ Btu when uncontrolled.

Since NO_x emissions are complex functions of boiler design, operation, and fuel characteristics, emissions vary widely, (e.g., for wall-fired units, the range is generally 0.7 to 1.3 lb NO_x per million Btu input), which leads to uncertainty on controlled emission rates using combustion modification.

The capital costs are dependent in part on site-specific variables, and the accuracy of the costs quoted is not better than -10% to +30%

ii) Flue Gas Treatment (FGT)

The leading method of FGT is injection of gaseous ammonia to reduce NO_x to harmless nitrogen. Operation without a catalyst requires very high temperatures and removal is limited to about 35 - 40%. With a catalyst, 90% or higher removal is feasible, but 80% gives much less operating difficulty and may be the upper practicable limit for high-sulfur coal.

iii) Flue Gas Recirculation (FGR)

FGR is used now for superheat control and has some beneficial effects on NO_x reduction. Generally, it is not a favored technique. Its costs are indeterminate.

iv) Process Choice

The process choice depends on the degree of control required. The processes are ranked within performance ranges in the table below.

NO_x removal efficiency level, %	Process ranking
90% or higher	1. Catalytic reduction[a] with more than the normal amount of catalyst, preceded by combustion modifications
50-80%	1. Catalytic reduction with a normal amount of catalyst[a] 2. Combustion modification (all types) followed by noncatalytic reduction (ammonia injection without catalyst)[a] 3. Combustion modification alone (for low part of range so as to minimize boiler problems) 4. Low-NO_x burners[b]
Below 30%	1. Staged combustion[b] 2. Low-NO_x burners 3. Flue gas recirculation (FGR) (except for coal)[b]

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[a] This technology has not been proven on coal-fired boilers.

[b] Used in combination with others if necessary to achieve the required reduction level.

C.1.2.3 Particulate Matter Control Technologies

i) Precipitation and Filtration

Electrostatic precipitation is currently the most prevalent technique employed for particulate control. Fabric filtration methosa are rapidly becoming more competitve particularly for low sulfur coals and for meeting very stringent emission standards.

ii) Wet Scrubbing

Wet scrubbers remove coarse particles cheaply and effectively but are not capable of meeting the emission regulations now in place. Multicylcone systems are generally in the same category. These systems are often feasible as pre-cleaners for very heavily loaded gas streams prior to precipitation or filtration.

iii) Process Choice

To meet the current U.S. New Source Performance Standards for particulates (0.03 lb/10^6 Btu), baghouses are superior for low-sulfur coal because the ash does not precipitate easily. For high-sulfur fuel, the situation is not clear; more experience with baghouses is needed. It is known, however, that precipitators are more cost effective for meeting the former 1971 standard of 0.1 lb/10^6 Btu.

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C.2 NON-FERROUS SMELTERS

Efforts to control air pollutant emissions from non-ferrous metal production processes have traditionally been focused upon the problem of SO_2 control. The SO_2 emissions from smelters fall roughly into two categories, strong and weak; i.e. greater or less than 4% SO_2 respectively. This terminology arises from the application of a sulfuric acid plant to control smelter SO_2 emissions. Such acid plants require a minimum SO_2 gas strength in order to be economically applicable, hence an off-gas stream having a sufficiently strong SO_2 concentration is a strong SO_2 off-gas. Those SO_2 off-gas streams having concentrations less than the minimum are weak SO_2 off-gas streams.

C.2.1 Description

Canada

In Canada there are a total of five copper smelters, three nickel-copper smelters, two lead smelters and three zinc smelters. Smelter locations are shown in Figure C.2.1 and smelter statistics in Tables C.2.1 and C.2.2. The lead and zinc smelters and the Afton and Kidd Creek Mines copper smelters already control 85 to +95% of their sulfur input. The major sources of smelter SO_2 emissions in Canada are copper and nickel smelters located in Manitoba, Ontario and Quebec.

United States

In the United States, there are a total of 15 copper smelters, 5 lead smelters and 5 zinc smelters. In the eastern U.S., there are four primary zinc smelters and two primary copper smelters. These smelters have relatively low SO_2 emissions because of the nature of the production processes and controls employed, and therefore, are not included as major emission sources of SO_2 for the purpose of this study. The major non-ferrous smelting capacity is located in the western U.S. with the largest concentration in the Arizona-New Mexico area (see Figure C.2.1 and Tables C.2.3 and C.2.4).

Process Descriptions

The type of ore (i.e. sulfide, oxide, etc) and its metal values determine the choice of metallurgical process to be used for its extraction. Usually there are accessory metallic elements, such as gold, silver, etc., present, which are also to be recovered in subsequent processing steps. There are a substantial number of processes which have been developed for copper and zinc and a fewer number for lead and nickel. These processes fall into two basic classifications: pyrometallurgical and hydrometallurgical. Hydrometallurgical processes are based upon the solution of the metal values in an aqueous medium followed by electrochemical winning of the metal values from solution. Hydrometallurgical processes are used principally for oxide ores or materials converted to oxides. With the exception of zinc production, hydrometallurgical processes are not as broadly applied for large scale systems as pyrometallurgical processes. In pyrometallurgical processing, the metal values are extracted by slagging and volatilizing the undesirable components. The sulfur contained in the ore concentrate is a fuel which furnishes heat for the pyrometallurgical processes; it is volatilized and oxidized, resulting in substantial sulfur dioxide emissions. Generalized process flow diagrams are given in Figure B.2.2, and SO_2 emission factors and typical emission stream concentrations are given in Table C.2.5.

Copper Processing

Smelting consists of either two or three distinct pyrometallurgical processing steps: (1) roasting, (2) smelting, and (3) converting. Sulfur in excess of the amount needed to ensure formation of a copper sulfide matte in the furnace can be eliminated by roasting. The calcine produced by the roaster, or the green concentrate if roasting is not used, is charged to the smelting furnace where the charge is forced through complex reactions involving melting, slagging and volatilization of impurities to form a copper matte.

Copper matte is a mixture of molten iron sulfide and copper sulfide. The relative proportions of the iron sulfide and copper sulfide (Cu_2S) vary over a wide range. The iron sulfide is preferentially oxidized to iron oxide and combines with a silica slagging agent to form a liquid iron silicate slag that is immiscible with the sulfide matte phase. The slag phase floats on top of the matte layer. As excess slag is formed, it is removed and discarded. The matte is periodically tapped and is further processed in a converter in which air is blown through the molten metal to remove iron and the other impurities and form blister copper. About 1 to 2 percent of the sulfur entering a smelter is lost in slags, 3 to 4 percent is released as fugitive emissions, and the remainder is contained as SO_2 in the gases from roasters, smelting furnaces, and converters. A total of about 2 tonnes of SO_2 is generated for each tonne of copper produced.

Although the three steps of copper smelting have the same functions in all smelters, there are significant differences in the equipment used, the operating conditions and the intermediate products and emissions produced. Two types of roasters, four types of smelting furnaces, and two types of copper converters are used commercially in North America.

In copper smelting, the major sources of weak SO_2 off-gas are the reverberatory furnace and multihearth roaster, followed by the fugitive emissions occurring from (1) the converter operation, (2) matte tapping, (3) slag tapping, and (4) ladle transfer.

Nickel Processing

The metallurgy of nickel processing is similar to copper and the same type of processing equipment is used. The sources of sulfur dioxide emissions are the same. However significantly more SO_2 is generated per tonne of metal produced than in the case of copper. Approximately 10 tonnes of SO_2 is generated overall per tonne of nickel produced. This is due to the large amounts of pyrrhotite associated with nickel ore bodies. A substantial portion of the pyrrhotite is separated in the mineral benefication stage. This may be subsequently processed to recover residual nickel, sulfuric acid and iron ore such as is done at INCO's iron ore recovery plant.

Lead Processing

The first processing step in a lead smelter is sintering. Sintering is performed to remove sulfur and to produce a material suitable for charging to the blast furnace. About 85 percent of the sulfur is removed by oxidation and the feed is fused into a porous clinker. The product from sintering is then processed in a blast furnace to produce lead bullion, an impure metal. Sintering is the only part of the lead smelting process that can emit large amounts of SO_2. Fugitive emissions of SO_2 also occur at the discharge end of the sinter machine, where the discharged material is broken into pieces. Low concentrations of SO_2 may occur in blast furnace off-gas. Processes that purify lead bullion emit no SO_2, although they do emit other pollutants.

In lead smelting, about 85 percent of the sulfur in the concentrate is liberated as SO_2 in the sintering step of the remaining 15 percent of the concentrate sulfur approximately half is eliminated as SO_2 in the off-gases from the subsequent processing steps and half in the solid products. In the sintering process, most of the sulfur is eliminated at the front end of the sinter machine. The strong gas stream is usually collected and controlled by a metallurgical acid plant. At least one smelter has installed a recirculation system for the weak stream which allows combination with the strong stream. Certain overseas smelters have practiced this approach for some time.

Zinc Processing

Two different pyrometallurgical processes are used to produce zinc metal from concentrate. The first step in both methods is to burn off almost all the sulfur by roasting. At least 95 percent of the sulfur is converted into strong SO_2, and, at most smelters, most of the remaining sulfur is converted into sulfates. The product of roasting, called calcine, is an impure zinc oxide, which usually contains less than 0.3 percent sulfide sulfur. Calcine is processed either electrolytically or pyrometallurgically into zinc metal. Roasting is the only significant source of emissions in a zinc smelter. The electrolytic process produces no SO_2 emissions. Pyrometallurgical production may create low concentrations of SO_2 (about 0.1 percent) in off-gas from sintering machines.

C.2.2 Control Technology

Off-gases from non-ferrous smelters basically fall into two categories, those with strong SO_2 strengths (defined as greater than 4% SO_2) and those with weak strengths (less than 4% SO_2). Strong gas streams are controllable using add-on technologies such as acid plants and liquid SO_2 plants. These processes are considered proven and, in most cases, affordable control options. Treatment of weak gas streams constitutes a more difficult and costly problem. Options available are:

1) use the add-on technology of flue gas scrubbing using either regenerative or non-regenerative processes;

2) modify the furnaces to produce a strong gas stream through measures such as oxygen enrichment; and

3) replace the sources giving rise to the weak SO_2 streams with alternative modern technology producing strong SO_2 streams, controlled by acid plants.

Flue gas desulfurization by scrubbing (FGS) is practiced by a number of smelters worldwide. The FGD systems employed are unique to each smelter. This is a result of the particular circumstance of each application in terms of economics for raw materials and by-product markets rather than technical suitability of the processes.

Upgrading of existing furnace operations to produce stronger SO_2 streams can be an effective approach to SO_2 control when coupled with acid plants. Alternative pyrometallurgical processes are of interest because they provide a strong SO_2 gas stream for control by a conventional acid plant, reduction in energy consumption, gas stream volumes, and operating costs.

Alternative hydrometallurgical processes eliminate the generation of uncontrollable SO_2 streams. The capital costs of hydrometallurgical processes are competitive with pyrometallurgical processes. The operating costs may be higher depending on the cost of electric power. However, electrolytic cell technology advances are being made in the battery and fuel cell areas which may have important implications for hydrometallurgy.

A large number of alternative approaches to achieve reductions in SO_2 emissions based upon various combinations of process and control technologies are technically possible; a number of the more important ones are given in Table A.4.1 in the Summary, Chapter A. In considering any approach, it is of paramount importance to consider the unique nature of each smelter. This uniqueness factor is determined by the nature of the ore concentrates and the metallurgy required to successfully treat these concentrates. It is these aspects that govern the selection of a metallurgical process for metal winning, and, in turn, the degree of sulfur containment. Each smelter requires an individual technical and economic assessment of feasibility.

In the selection of the production and control processes the following factors must be considered and evaluated:

1) amenability to SO_2 control;

2) applicability of the production process to the concentrates to be treated (at this time, it has not yet been shown that flash or continuous smelting can be successfully applied to concentrates with certain high impurity level - such as lead and arsenic);

3) energy consumption, including the types and qualities of the energy used;

4) capital and operating costs;

5) amenability to improved industrial hygiene conditions;

6) flexibility to changing operating conditions such as fluctuating levels of production, composition of concentrates, etc;

7) creation and control of environmental problems whether air pollution, water pollution or solid waste disposal;

8) recovery of primary metals and by-products; and

9) availability of markets for sulfur by-products.

The control process for SO_2 emissions must be evaluated against the factors listed above, and must also include costs for pollution by-products disposal, whether as a marketable or throwaway by-product.

C.2.3 Control Technologies and Costs

As discussed in the previous section, there are a number of technologies available for application to smelters for control of SO_2 in both strong and weak streams. However, application of most, excepting acid plants, tends to be limited by economic aspects of the market for the by-product produced, the capital and operating costs, or lack of extensive experience with (and confidence in) certain technologies, especially those for weak stream control. Control processes and costs, where available, are discussed in the following sections and in Appendix 5.

C.2.3.1 Treatment of Strong SO_2 Off-Gas Streams

Off-gas streams having high SO_2 strengths are, in principle, readily amenable to SO_2 control using established, proven technology. The most commonly used process is the metallurgical sulfuric acid plants. The cost of fixing sulfur dioxide using this technology is shown in Table 5.2 in Appendix 5. SO_2 is also controlled by fixing the gas as marketable liquid SO_2. However, application of this process is more limited as a result of the smaller market for the by-product. The cost of fixing SO_2 using this process is shown in Table 5.4 in Appendix 5.

Both processes require a continuously flowing gas of at least 4% SO_2. Therefore they are not normally applicable to gases from reverbatory furnaces or multi-hearth roasters. Gases from Peirce-Smith converters can be treated in this way provided that they can be scheduled to produce a fairly continuous stream or that a relatively large continuous higher concentration stream is available for mixing with the converter gases. Tight-fitting, water-cooled hoods would also have to be provided for the converter off-gases. The costs that have been developed for the two processes are for new facilities. Costs for existing facilities would be similar except that allowance would have to be made for changes to the existing processes.

The majority of the non-ferrous smelters currently controlling SO_2 emissions produce sulfuric acid as a by-product. It is anticipated that this trend will continue for some time. The disposal of the by-product sulfuric acid is likely to be a problem where the smelter is remote from sulfuric acid markets or where existing sulfuric acid markets are already supplied with lower cost acid. In these cases the smelter acid can only be marketed at a loss, which increases with the distance from market. Non-market constraints such as international trade agreements, lack of adequate transportation facilities, etc., may prevent sale of acid in some areas. The marketing of the acid may impose costs on the smelter which increase the cost of control to a point where smelter closure is considered.

A related problem is the high cost and environmental problems associated with the neutralization of acid which cannot be marketed because of high cost, remote smelter location or other reasons. The costs and environmental factors depend largely on the availability and cost of a limestone (not always close to smelter). The environmental problems of disposal of the neutralized acid are similar to those referenced in C.1.2.1 (vi). The cost of acid neutralization and gypsum disposal has to be added to the cost of sulfur dioxide abatement. Neutralization disposal costs are estimated at approximately $31 (U.S., 1981) per tonne of acid neutralized.

Another factor in marketing smelter sulfuric acid is that the demand cycle for sulfuric acid may not coincide with the demand cycle for metals, raising the issue of the disposal of acid, that is excess to market demand at a time when metal demand is high.

Technology for fixing sulfur as elemental sulfur is also available. However, it is much more expensive ($129/tonne sulfur) than producing either sulfuric acid or liquid SO_2. A relatively concentrated SO_2 stream of low oxygen content is required together with substantial quantities of reductant. Therefore it is not applicable to most existing smelter gas streams.

C.2.3.2 Treatment of Weak Gas Streams using Flue Gas Scrubbing

The 0.5 to 1.5% SO_2 average concentration in reverberatory furnace off-gas is not sufficiently high for direct processing of the gas in a conventional sulfuric acid plant. For this reason, FGS systems have been incorporated at a few smelters under specific conditions. They may be classified as regenerative and non-regenerative; the former produces SO_2 as a more concentrated gas, and the latter generally converts it to a throwaway by-product.

The non-regenerative systems essentially neutralize the SO_2, converting it into stable form which can be disposed of with minimal adverse effects on the environment. Regenerative systems absorb the SO_2 and then regenerate it as a more concentrated SO_2 stream which can then be used to make either liquid SO_2, sulfuric acid, or sulfur. In those cases where the sulfuric acid market is such that additional production is not saleable, the non-regenerative systems would seem to be the logical choice for controlling SO_2 from the smelter reverberatory furnace. In those cases where a by-product is to be produced, several possible concentration systems have been proven feasible at full scale operations on reverberatory furnace off-gases. The costs, however, are substantial and each retrofit system must be considered on an individual basis.

As shown in Table 5.3 in Appendix 5, weak stream control technology is practised at some European and Japanese smelters. One North American smelter uses ammonia scrubbing, and a molybdenum roaster uses limestone scrubbing. The U.S. Environmental Protection Agency has stated that lime, limestone, magnesium oxide and ammonia wet scrubbing systems have been adequately demonstrated to be technically feasible. However, because of lack of experience and the question of the economic feasibility of applying wet scrubbing systems to smelter gases in North America, the problem of weak SO_2 off-gas control remains the major issue of smelter pollution control. Flakt and Boliden are jointly developing a citrate system for smelter weak SO_2 which is the pilot stage. The new Afton Mines smelter (Canada) employs a dual alkali system. Currently the state-of-the-art is such that FGD by wet scrubbing can be accomplished but there are risks in the selection, design and application of such systems owing to lack of extensive experience on various types of concentrates. Costs range from $95-135 per tonne of SO_2 collected (see table C.2.6).

C.2.4 Process Modification

C.2.4.1 Processes that Provide Gases More Amenable to SO_2 Control

In reviewing the possible approaches to SO_2 control, it becomes evident that an increase in concentration of the off-gas is desirable. This tends to reduce cost of processing equipment such as FGS or concentration systems. It is also desirable in all cases to minimize the gas volume leaving the furnace simply to reduce the initial and operating costs of the gas handling equipment. There is a broad range of process modifications available to achieve a sufficient increase in the strength of the SO_2 off-gas to permit control by a metallurgical acid plant. These alternatives range from modifications of the roaster operation to replacement of the reverberatory furnace with a modern flash or continuous smelting process.

The SO_2 off-gas from the reverberatory furnace can be upgraded to a strong gas through a combination of techniques such as:

1) reducing uncontrolled air infiltration into the furnace and the consequent off-gas dilution;

2) reducing the fuel firing rate and the amount of combustion air (also a diluent) required;

3) oxygen enriched smelting; and

4) blending of strong streams with weak streams.

Oxygen enrichment of reverberatory furnace air has been practiced in the USSR, Chile, and Japan for many years. The general conclusion is that the increase in SO_2 concentration resulting from O_2 enrichment can vary from 0.3 to as high as 16 percentage points. The Caletones smelter in Chile has obtained 5 to 7 percent SO_2 operationally from a green feed reverberatory furnace. Oxygen enrichment was originally intended to increase production rather than control SO_2. However, the increase in SO_2 concentration coupled with the reduction in off-gas volume has allowed direct processing in an acid plant in some cases, or blending with stronger gas streams. Calculations and tests made at various plants show that when using a blast containing 28 to 30 percent oxygen, the amount of SO_2 in the reverberatory furnace gases is approximately 4 percent. Preheating and enriching blasts with oxygen intensify the smelting process and, according to approximate calculations, make it possible to increase the specific fusion in the reverberatory furnaces from 6-8 to 10-12 tons of charge per square metre of hearth area per day when smelting roasted materials.

The Oxygen Sprinkle process (a recent development by Queneau, Schuhmann, and Dravo) is an extension beyond oxygen enrichment, approaching flash smelting, which is designed to permit retrofit to an existing reverberatory furnace with the addition of oxygen burners, an oxygen plant, and new gas off-takes.

Many existing smelters have equipment such as multiple-hearth roasters and reverberatory furnaces which produce gases too low in SO_2 for direct processing to sulphuric acid. In copper smelting, the multiple-hearth roasters can be replaced in some cases by fluid bed roasters, and thus up to 86-93 percent of the total smelter sulphur can be produced in an SO_2 concentration high enough for sulphuric acid production. An even greater improvement can be achieved by replacing both multiple-hearth roasters and reverberatory furnaces with modern smelting units which release 60 percent or more of the sulphur as high-strength SO_2 gas, resulting in about 95 percent sulfur containment for the smelter.

Conventional converting in most smelters is a batch operation that produces a gas stream of variable SO_2 content which is difficult to process into sulphur by-products. Gases from Peirce Smith converters can be treated in acid plants provided that they can be scheduled to produce a fairly continuous stream or that a relatively large continuous, high concentration stream is available for mixing with the converter gases. Tight fitting hoods would also have to be provided on the converters to limit air in-leakage. Continuous smelting processes such as the Mitsubishi process and the Noranda process produce a continuous high-strength gas. However, these processes have been proven only for certain "clean" copper concentrates. Alternative production processes for copper and nickel based upon the more advanced oxygen smelting concepts also have distinct advantages in reduced energy consumption, productivity, and capital and operating cost savings, in addition to improved sulfur containment.

Estimates for representative processes of the attributes of sulfur containment, energy consumption, and capital costs are compared in Table 5.5 in Appendix 5. It is seen that sulfur containment improves in stages with well-operated calcine charge reverberatory furnaces approaching 90 to 93 percent, the more modern electric, flash, and Noranda processes approaching 96 percent, and finally the totally enclosed systems such as Mitsubishi, QS, and WORCRA offering 98+ percent, depending upon the degree of acid plant tail gas control. Analysis of this information obtained from three studies indicates that the estimates for the specific energy requirements of a given process differ rather significantly between the studies.

While the results of these three energy studies are not directly comparable due to the differences in approach, their conclusions as to relative energy requirements serve as a basis for this present comparison. Only the Pitt and Wodsworth study provided information on energy requirements of the developing processes; therefore, no comparison is possible for these. The Bureau of Mines study applies only to processes currently used domestically, but is included as a basis of comparison of relative energy requirements. Kellogg and Henderson do include some foreign technology in their assessment, but are limited in this respect.

The available data on costs of alternative technology are more inconsistent than those available on energy consumption. In general, the estimates that are published show most of the alternative technologies to be of lower capital cost than a green-field smelter of conventional design. While cost estimates for technologies in preliminary phases of development are notoriously over-optimistic, the nature of many of the new process technologies is such that the estimated capital and operating costs savings appear reasonable.

C.2.4.2 Processes that Eliminate SO_2 Formation

Hydrometallurgical processing of nickel sulfide concentrates has been practised by one Canadian company, Sherritt Gordon, for 20 years. Hydrometallurgical processing of copper is practiced at two U.S. sites (Duval and Cypus) and processing of zinc in Canada by Cominco. While these processes do not produce SO_2 gas, one cannot always accept hydrometallurgical processes as the most desirable solution to the metals extraction problem. They have not been widely used for copper because of a number of factors, such as: the process technology is not sufficiently developed; recovery of precious metals is difficult or impossible; and energy costs may be high depending on the cost of electricity. It appears that application to copper may be limited by economics to installations of less than 50 000 tonnes per year. While hydrometallurgy can significantly reduce direct smelter air emission problems, it appears that solid and liquid waste streams are either increased or more heavily contaminated and that energy requirements are increased as well.

C.2.4.3 Processes that Reduce Sulfur Input to the Metallurgical Processes

In some cases, it is possible to modify the ore beneficiation processes to reject a greater amount of sulfide minerals than normal. This is practised, for example, in the nickel industry where part of the pyrrhotite is rejected in the milling and concentration stage thus reducing the sulfur to metal ratio of the concentrate entering the smelter. Some metal values (including nickel, cobalt, platinum, etc.) are lost with the rejected pyrrhotite, and a compromise is made between metal values lost and sulfur rejected.

C.2.5 Comparison of Abatement Costs for the Different Options

The cost of abating sulfur dioxide varies according to the control technology used. The cost of implementation of each technology at different smelters is also widely variable depending on the smelting process used, the amount of smelter retrofit required, availablity of markets for by-products, off-gas flow rates, SO_2 content, etc. Table C.2.6 compares relative costs for some of the options considered. These costs are general and are considered accurate to within a range of ± 30%. The following points are noted:

a) SO_2 abatement using contact sulfuric acid plants provides the lowest cost per tonne ($33-52) given an adequate SO_2 strength. This estimate assumes that the acid can be sold at a price sufficient to cover the costs of transportation and marketing. In some instances depending on smelter location and competition for acid markets the sales revenue may be insufficient to cover the transportation and marketing costs. The losses from acid sales will have to be borne by the smelter, increasing the cost of SO_2 fixation. In some instances neutralisation may be required further increasing the cost.

b) process modification to provide gases with stronger SO_2 strengths and enable fixation in acid plants provides a viable alternative for SO_2 control, however, no estimates are available for the cost of these modifications;

c) treatment of dilute gases using FGS process have the highest operating costs per tonne of SO_2 removed ($108-154). The cost for the regenerative options are lower than in the case of non-regenerative options as a result of reagent recovery and consequent cost savings; and

d) the cost per tonne of SO_2 removed for the process replacement options which enable gases to be treated in sulfuric acid plants is considerable ($115) and approaches that of flue gas scrubbing. The major cost component is amortisation of the capital.

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TABLE C.2.1

Summary of Canadian Copper and Nickel Smelter Statistics

Smelter Location	Capacity tonnes/year	Process Equipment	Control Equipment	% Sulfur Containment	SO_2 Emissions tonnes/year (1980)
Hudson Bay Mining and Smelting Company Limited, Flin Flon, Manitoba	65 000 Cu 73 000 Zn	13 Multihearth roasters 1 Reverberatory Furnace 3 Converters	NIL	NIL	248 000
Inco Limited Thompson, Manitoba	45 000 Ni	5 Fluid Bed Roasters 5 Electric Furnaces 7 Converters	NIL	NIL	214 000
Inco Limited Copper Cliff, Ont.	164 000 Ni 154 000 Cu	33 Multihearth roasters 6 Reverberatory Furnaces 1 Inco Oxygen Flash Furnace 19 Converters	Liquid SO_2 Plant Acid Plant	44	812 000
Falconbridge Nickel Mines Ltd. Sudbury, Ontario	45 000 Ni 27 000 Cu	2 Fluid Bed Roasters 2 Electric Furnaces 4 Converters	Acid Plant	56	122 000
Noranda Mines Ltd. Noranda, Quebec	200 000 Cu	2 Reverberatory Furnaces 1 Noranda reactor 5 Converters	NIL	NIL	538 000
Noranda Mines Ltd. Murdochville, Quebec	80 000 Cu	1 Fluid Bed Roaster 1 Reverberatory Furnace 2 Converters	Acid Plant	59	91 000
Afton Mines Ltd. Kamloops, B.C.	27 000 Cu	1 Top Blown Rotary Converter	Double Alkali Scrubber	80	2 000
Kidd Creek Mines Ltd. Timmins, Ontario	59 000 Cu	Mitusbishi Continuous Smelting Process	Acid Plant	95+	5 000

TABLE C.2.2

Summary of Canadian Lead-Zinc Smelter Statistics

Smelter Location	Capacity tonnes/year	Process Equipment	Control Equipment	% Sulfur Containment	SO_2 Emissions tonnes/year (1980)
Cominco, Ltd. Trail, B.C.	247 000 Zn 144 000 Pb	2 Sinter Machines 2 Fluid Bed Roasters 2 Blast Furnaces	Acid Plants Ammonia Scrubbing	94+	24 000
Brunswick Mining & Smelting Corp. Ltd., Belledune, N.B.	63 000 Pb	1 Sinter Machine 1 Blast Furnace	Acid Plants	95+	13 000
Kidd Creek Mines Ltd., Timmins, Ont.	108 000 Zn	2 Fluid Bed Roasters	Acid Plants	95+	5 000
Canadian Electrolytic Zinc, Ltd., Valleyfield, Quebec.	218 000 Zn	4 Fluid Bed Roasters	Acid Plants	95+	11 000

TABLE C.2.3

Summary of U.S. Copper Smelter Statistics

Smelter Location	Capacity tonnes/year	Process Equipment	Control Equipment	% Sulfur Containment	SO_2 Emissions tonnes/year
Asarco, El Paso, Texas	95 000	4 Multihearth Roasters 3 Reverberatory Furnace Converters	Acid Plants	70	44 000
Asarco, Hayden, Arizona	148 000	12 Multihearth Roasters 2 Reverberatory Furnaces 5 Converters	Acid Plants	35-40	107 000
Asarco, Tacoma, Washington	83 000	6 Multihearth Roasters 10 Multihearth Roasters 2 Reverberatory Furnaces 4 Converters	Acid Plants DMA	35-40	102 000
City Services* Copperhill, Tennessee	18 000	Fluid Bed Roaster 2 Electric Furnace Converters	Acid Plants		
Inspiration, Miami Arizona	124 000	Rotary Dryer Electric Furnace 5 Converters	Acid Plants	80	17 000
Kennecott Hayden, Arizona	66 000	Fluid Bed Roaster Reverberatory Furnace 3 Converters	Acid Plants	90	22 000
Kennecott Hurley, Arizona	66 000	Rotary Dryer 2 Reverberatory Furnaces 4 Converters (3 operating)	Acid Plants	60	65 000
Kennecott McGill, Nevada	41 000	Reverberatory Furnace Converters.	NIL	1.5	86 000

* NOTE: Smelter is part of an acid production facility and is not a typical smelter.

TABLE C.2.3 (continued)

Summary of U.S. Copper Smelter Statistics

Smelter Location	Capacity tonnes/year	Process Equipment	Control Equipment	% Sulfur Containment	SO_2 Emissions tonnes/year
Kennecott Garfield, Utah	231 000	2 Rotary Dryers 3 Noranda Reactors 4 Converters	Acid Plants	87	27 000
Magma San Manuel, Arizona	165 000	3 Reverberatory Furnaces 6 Converters	Acid Plants	45	104 000
Phelps Dodge Ajo, Arizona	58 000	3 Reverberatory Furnaces 3 Converters	Acid Plants	50	54 000
Phelps Dodge Douglas, Arizona	104 000	24 Multihearth Roasters 3 Reverberatory Furnaces 5 Converters	NIL	1.5	258 000
Phelps Dodge Hidalgo Playas,	115 000	Rotary Dryer Flash Furnace Slag Furnace 3 Converters	Acid Plants	91	21 000
Phelps Dodge Morenci, Arizona	146 000	Fluid Bed Roaster 5 Reverberatory Furnaces 9 Converters	Acid Plants	62	102 000
White Pine Michigan	75 000	Rotary Dryer 2 Reverberatory Furnaces 2 Converters	NIL	0	48 000

TABLE C.2.4

Summary of U.S. Lead and Zinc Smelter Statistics

Smelter Location	Capacity tonnes/year	Process Equipment	Control Equipment	% Sulfur Containment	SO_2 Emissions tonnes/year
Amax, Boss, Missouri	127 000 Pb	Updraft sinter (dual stream) Blast furnace	Acid Plants	74	-[1]
Amax, East St. Louis, Illinois	76 000 Zn	2 Fluid bed roasters Electrolytic	Acid Plants	90	-
ASARCO, Columbus, Ohio	20 000 Zn	1 Weatherhill furnace	Acid Plants	90	-
ASARCO, Corpus Christi Texas	98 000 Zn	1 Fluid bed roaster Electrolytic	Acid Plants	?	-
ASARCO, East Helena Montana	109 000 Pb	Updraft sinter Blast furnace	Acid Plants	89	-
ASARCO, El Paso, Texas	109 000 Pb	Updraft sinter Blast furnace	Acid Plants	?	-
ASARCO Glover, Missouri	100 000 Pb	Updraft sinter (dual stream) Blast furnace	Nil	0	-
Jersey Miniere Clarksville, Tennessee	90 000 Zn	1 Fluid bed roaster Electrolytic	Acid Plants	99	-
National Zinc, Bartlesville Oklahoma	45 000 Zn	2 Fluid bed roasters Electrolytic	Acid Plants	?	-
St. Joe Herculaneum Missouri	204 000 Pb	Updraft sinter (dual stream)	Acid Plants	59	-

[1] Not available at time of preparation of report

TABLE C.2.5

SO_2 Emission Factors

Metal	Emitting Equipment	SO_2 Off-Gas Strength % Min-Max	SO_2 Off-Gas Strength % Typical	Percent of Smelter Feed Sulfur Removed	Emission Factor for Emitting Equipment kg SO_2/tonne of product
Copper	Multiple Hearth Roaster	1-3	less than 2	20-50	325-625
	Fluid Bed Roaster	10-14	12	20-50	325-625
	Reverberatory Furnace, Green Charge	0.5-2.5	1.5	20-40	275-800
	Reverberatory Furnace, Calcine Charge	-	-	10-30	150-475
	Electric Furnace	4-8	-	-	-
	Outokumpu Flash Furnace	10-14	-	45-55	-
	Inco Flash Furnace	10-14	-	45-55	-
	Mitsubishi 3-Furnace System	10	-	-	-
	Noranda Furnace	8-20	13	50-75	-
	Peirce-Smith Converter Green Charge	0-20	3.5-8	60-80	850-1800
	Peirce-Smith Calcine Charge	0-20	3.5-8	40-50	975-1075
	Hoboken Converter	-	8	-	-
Lead	Updraft Sinter Machine			85	575-1075

TABLE C.2.5 (continued)

SO_2 Emission Factors

Metal	Emitting Equipment	SO_2 Off-Gas Strength % Min-Max	SO_2 Off-Gas Strength % Typical	Percent of Smelter Feed Sulfur Removed	Emission Factor for Emitting Equipment kg/MT
	Single Exhaust		2	2	-
	Split Exhaust:				
	Strong	4-7	6	5.7	-
	Weak	-	0.5	0.5	-
	Recycle	less than 4	less than 6	6	-
	Blast Furnace		0.5	7	22.5
	Slag	-	-	8	-
Zinc	Ropp Roaster	0.7-1.0	1	93-97	-
	Multiple Hearth Roaster	1-3	less than 2	93-97	550
	Flash Roaster	8-12	10	93-97	550
	Fluid Bed Roaster	7-14	12	93-97	550
	Down-Draft Sinter Machine	0.04	-	1-6	-
Nickel	Multi-hearth Roaster	1-3	less than 2	25	1000
	Reverberatory Furnace, Calcine Charge	1-2	1.5	15	600
	Peirce-Smith Converter	0-12	3-6	25-40	1 600-1 800
	Fluid Bed Roasters	10-14	12	45-50	3 600-4 800
	Electric Furnace	4-8	-	8-20	800-1 700

TABLE C.2.6
Comparison of Cost of Abating SO_2 by Various Options(1)

	Off-gas			Capital Cost	Operating Cost		Total Annual Cost	Cost Per tonne SO_2(2)
Control Options	SCFM	% SO_2	SO_2 tonnes per day	10^6 $	10^6 $	Amortization 10^6 $	10^6 $	removed $
Single contact acid plant on strong gas stream(3)								
- continuous gas only	27 000	12	346	17	1.5	2.5	4.0	33
- variable gas only	49 000	5-8	346	28	2.2	4.1	6.3	52
- continous gas & variable gas	36 000	6-12	346	22	1.8	3.1	4.9	40
Non-regenerative scrubbing of weak gas stream(4)								
- lime	400 000	1	430	40	17.4	5.7	23.1	154
- limestone	400 000	1	430	47	13.4	6.8	20.2	134
Regenerative scrubbing of weak gas stream(4)								
- MgO and acid plant	400 000	1	430	65	10.9	9.3	20.2	134
- Citrate and acid plant	400 000	1	430	58	7.9	8.3	16.2	108
Replacement of process producing weak gas stream with modern process (5)								
- existing old smelter process (uncontrolled)				--	26.0(6)	---	26.0	---
- modern process	63 000	8	540	215	22.0(6)	30.9	52.9	115(7)

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1. All costs are in 1981 U.S. dollars. Capital costs is amortized over 12.5 years at 10% interest.
2. Production is based on 350 operating days per year and assuming 100% control of SO_2.
3. Figures are derived from "A Study of Sulfur Containment Technology in the Non-ferrous Metallurgical Industry", Economic and Technical Review Report EPS-3-AP-79-8, Air Pollution Control Directorate, Environment Canada, April 1980.

TABLE C.2.6 (continued)

4. Non-regenerative and regenerative scrubbing of weak gas cost estimates are taken from the EPA data presented in the Appendices. The cost estimates for the regenerative scrubbing of weak gas stream also include a capital cost of $20 million and an annual operating cost of $6.8 million for a 660 tonnes per day sulfuric acid plant.

5. The cost estimates are for a copper smelter producing 100 000 tonnes per annum of copper. Modern processes are processes such as the INCO, Noranda and Mitsubishi processes.

6. The annual operating cost of a fully depreciated, existing reverb based smelter with no SO_2 controls is estimated to be about $26 million. The operating cost of the modern processes is approximated at $22 million.

7. The difference between the annual operating cost for the facility and the old facility are allocated to SO_2 control. The cost per tonne SO_2 fixed is computed assuming 100% SO_2 capture.

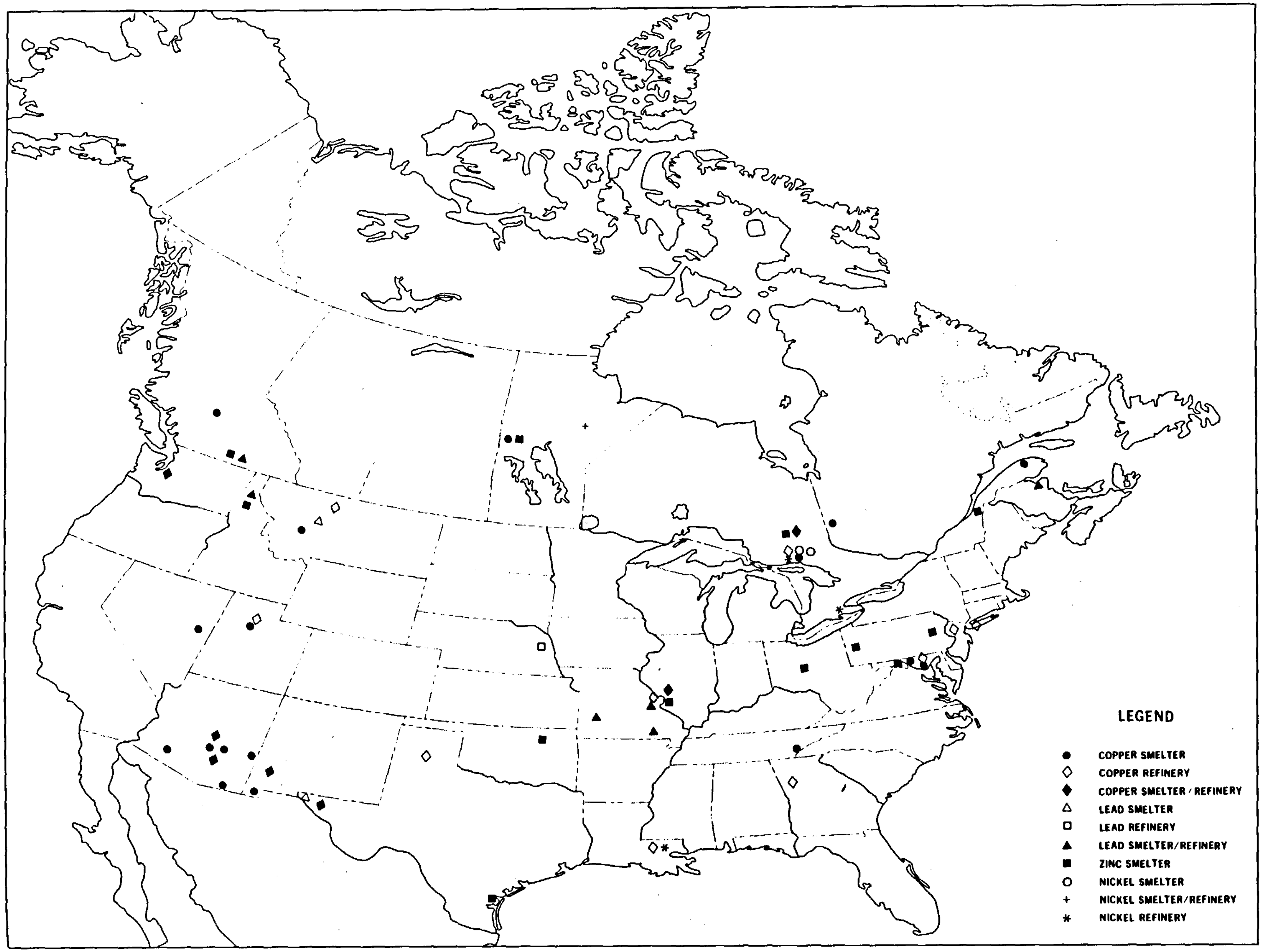
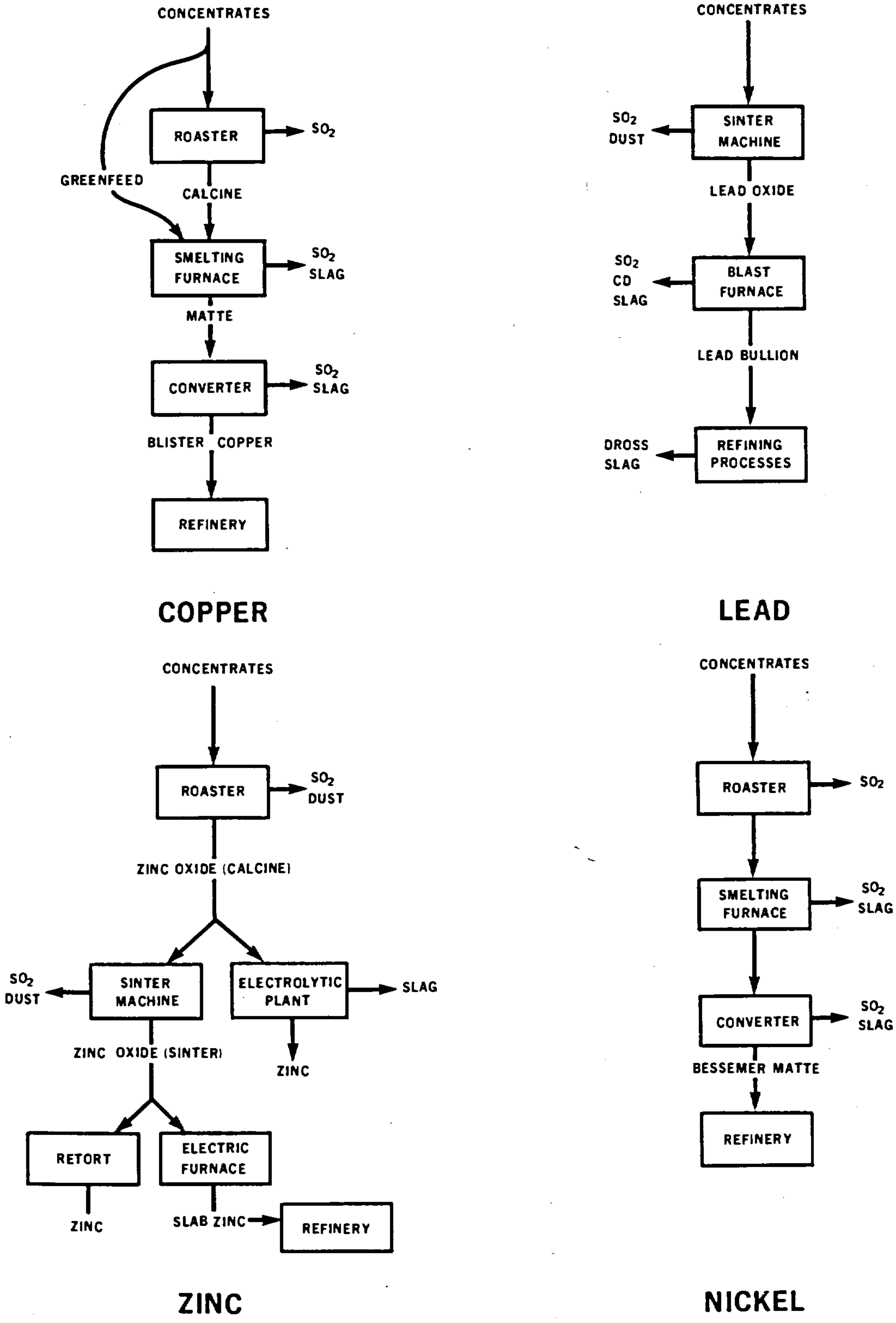


FIGURE C 2.1 PRIMARY NORTH AMERICAN NON-FERROUS SMELTING AND REFINING LOCATIONS



COPPER

LEAD

ZINC

NICKEL

FIGURE C.2.2. GENERALIZED FLOW DIAGRAMS FOR SELECTED PYROMETALLURGICAL PROCESSES

C.3 MOBILE SOURCES

C.3.1 Description

In the transportation sector gasoline and diesel-powered road vehicles account for about 77% of NO_x emissions while a further 21% comes from non-highway applications of gasoline and diesel engines. Emissions of SO_x from mobile sources are negligible (about 3.3% of man-made emissions).

C.3.2 Control Technologies

C.3.2.1 United States-New Vehicles

In the United States, tailpipe emission standards are in effect for a variety of light and heavy-duty vehicles, including motorcycles and airplanes.

In examining emissions of any pollutant from road vehicles one can divide the subject neatly into two parts: the design performance of vehicles, usually covered under new vehicle/ engine emission regulations, and the actual emissions performance of vehicles in consumers' hands, including both the amount and kind of use each vehicle sees.

C.3.2.1.1 Light-Duty Vehicles

Current emission standards are in effect for light-duty vehicles (LDV) which require a 90% reduction in hydrocarbons (HC) and carbon monoxide (CO), and a 75% reduction in nitrogen oxides (NO_x) as compared to 1970 model passenger cars.

There have been a series of emission control devices on passenger cars since the 1960's; however, beginning with the 1972 production models, emission control devices began to bring about significant reductions in air pollutants. In 1975, the catalytic converter was introduced on a large scale and has since become the primary system for controlling HC and CO. The technology for meeting the current automobile emission standards employs the catalyst technology coupled with a series of electronic and vacuum sensing devices which detect and control selected engine operating parameters. A so-called three-way catalyst (incorporating NO_x reduction as well) is being used on many new cars.

All the federal emission standards apply only to new production cars. Because the standards themselves have changed over time, and because it takes 8 to 10 years for an effective turnover of the vehicle fleet, it will still be a number of years before the total potential of the federal emission standards for LDV can be fully realized. Nevertheless, substantial reductions in vehicular emissions have already occurred for HC and CO. Per-vehicle-reductions for NO_x are also significant for new vehicles, but aggregate emissions are not.

C.3.2.1.2 Light-Duty Trucks

Because light-duty trucks (LDT) perform different functions than passenger cars, it is difficult to achieve the same level of emission reduction even though the same engines are interchangeably used in many cases. Consequently, the U.S. emission standards for LDT are somewhat less stringent than corresponding standards for passenger cars. For comparison, emission standards (in grams/mile) for model year 1981 LDT and LDV are listed below:

	HC	CO	NO_x
LDV (1981)	0.4	3.4	1.0
LDT (1981)	1.7	18.0	2.3
LDT (1983)	0.8	10.0	2.3 (possibly 1.2)

Generally, the same basic technology is used for both LDT and LDV. However, some of the electronic sensors or such add-on systems as the air pump may not be required. The cost of the control system will be very similar to that previously presented for LDV.

C.3.2.1.3 Heavy-Duty Trucks (HDT)

HDT are usually divided into two categories, gasoline-powered and diesel-powered. Control technology for both categories is available. The Clean Air Act Amendments of 1970 require that standards be established in the U.S. which will provide a 90%, 90%, and 75% reduction in HC, CO, and NO_x respectively, as compared to the amounts produced in 1973. For HC and CO, the technology is available to achieve these reductions; however, the availability of technology for achieving the required reduction in NO_x, particularly for the diesel engine, is questionable.

C.3.2.2 United States - In-Use Vehicles

C.3.2.2.1 Transportation Control Measures

If emission reductions beyond those achievable with tailpipe standards are required, transportation control measures can be used. These measures involve a host of possible alternatives ranging from simple cost-saving programs such as car pooling to extensive major rerouting of traffic, gasoline rationing or mass transit systems. Because of the variety of options, it is difficult to estimate the cost of such programs, but simple and inexpensive options may offer some emission reduction potential (maybe 5%). Generally, these less expensive options also offer some form of fuel savings.

C.3.2.3 Canada - New Vehicles

Although in Canada new light-duty vehicles are currently subject to an emission standard for NO_x of 3.1 grams per mile (g/mi), many of the vehicles meet the U.S. standard of 2 g/mi for the late '70's models and, from 1981 on, 1 g/mi. Thus the weighted average design emission level can be expected to remain well under the regulated 3.1 g/mi. The government is currently conducting a Social and Economic Impact Assessment of a 1.0 g/mi standard beginning in 1985.

Because both the design and pricing policies vary widely for vehicle manufacturers selling in Canada it is not possible to accurately calculate the cost to Canadians for the pollution control accomplished.

C.3.2.4 Canada - In-Use Vehicles

The actual NO_x emissions from vehicles in consumers' hands are affected by a large variety of factors; notably the general state-of-tune of the vehicle, and, recently discovered to be of major importance, direct tampering with NO_x emission controls which causes fleet emissions to be about 15% more than they should be.

A national inspection and maintenance guideline for the control of excess emissions and fuel consumption by in-use vehicles will soon be promulgated. Although not currently part of the guidelines per se, a visual check of those engine components controlling NO_x might reduce the excessive emissions due to tampering, at an insignificant extra cost to the inspection program.

C.4 PETROLEUM REFINING

This sector contributes a relatively small amount of SO_2 and NO_x to the total emissions from all sources. In Canada, petroleum refining (including fuel combustion) contributes less than 5.5% of the total nationwide SO_2 emissions and less than 2.5% of the NO_x emissions. For the U.S., these relative amounts are 3.8% and 1.04% respectively. Because this source represents such a small contribution on an aggregate basis, it is not treated in the same depth as large contributing sources.

C.4.1 Description

Canada

There are 33 operating refineries located across Canada, with 4 in the Maritimes, 7 in Quebec, 8 in Ontario, 1 in the Northwest Territories and 12 in Western Canada. Annual emissions for this industry sector are 263 000 tonnes/year SO_2 (92 000 from refining processes; 171 000 from combustion processes) and 45 800 tonnes/year NO_x (4 400 from refining processes, 41 400 from combustion processes). These emissions result from refinery process heaters and boilers, sulfur recovery plants, fluid catalytic cracking units, incinerators and flares.

United States

As of January 1979, there were 303 operating petroleum refineries in the U.S. with a total capacity of about 18 million barrels per calendar day (3.0×10^9 liters). In terms of total mass emissions of SO_2 and NO_x, petroleum refineries contribute a relatively small percentage of the total U.S. emissions of these pollutants. Specifically, refineries contribute 908 000 tonnes of the SO_x emissions and 200 000 tonnes of the NO_x emissions. Geographically a majority of the U.S. refinery capacity is in the Gulf Coast and West Coast areas of the United States, but a significant portion is in the north central (2.4×10^6 BPD, 14%) and northeastern (1.8×10^6 BPD, 10%) parts of the country. Existing fuel gas and sulfur plant regulations, and anticipated regulations for sulfur oxides from fluid catalytic cracking (FCC) units indicate that any increased refinery capacity will have the minimum emissions of SO_x and NO_x.

No detailed assessment has been published on the contributions of SO_x and NO_x emissions resulting from refinery fuels used in process heaters and boilers.

No grass-roots refinery capacity is expected to be added in the near future. However, an indeterminate amount of refinery upgrading which includes FCC capacity is expected to be added over the next few years. This upgrading may increase or decrease SO_x and NO_x emissions depending on the extent to which new controlled processes replace old uncontrolled ones. There is no study available at this time that predicts what refinery emissions will be as a result of the anticipated upgrading.

Production Processes

Refineries differ in their processing layout, depending on their capacity, type of crude oil processed, complexity of the processes involved, product specifications, and product requirements. Generally, the following processes are used in petroleum refining after washing crude oil with water for salt removal (desalting).

Separation

1) Atmospheric distillation, to separate light and/or heavy oil fractions
2) Vacuum distillation, to separate heavy oil fractions into gas-oil, lube-oil, and residue

Conversion

1) Catalytic cracking
2) Catalytic naptha reforming
3) Light hydrocarbon processing
    (i) polymerization
    (ii) alkylation
4) Isomerization
5) Coking
    (i) Delayed
    (ii) Fluid-bed
6) Desulfurization of fuel oils
7) Sulfur recovery by Claus Process

Treating: removal of H_2S and mercaptans from light hydrocarbons by amine and chemical treatment (sodium plumbite or copper chloride).

Blending: blending of base stocks to meet the applicable specifications.

C.4.2 Control Options

The bulk of the sulfur oxide emissions are (about equally) attributable to three operations: fuel combustion, catalyst regeneration, and sulfur recovery.

Available technologies could be installed to substantially reduce SO_2 emissions from FCC regenerators and sulfur plants on existing reformers, where not already in place. Emissions could also be reduced significantly if the refineries switched to low-sulfur fuels in the refinery fuel system.

C.5 INDUSTRIAL, RESIDENTIAL, COMMERCIAL FUEL COMBUSTION (STATIONARY SOURCES)

Sulfur and nitrogen oxide emissions from non-utility fuel combustion in Canada in 1980 were about 826 000 tonnes and 395 000 tonnes respectively. For the United States, these sources accounted for some 3.2 million tonnes of SO_2 emissions and 4.2 million tonnes of NO_x emissions in 1980. The vast majority of these emissions are associated with heavy and light oil combustion and as a result are mainly confined to the larger urban and industrial areas.

Control technology in this sector is size specific, with FGD and low-NO_x combustion modifications applicable to the larger-sized combustion units of the industrial sector. Control technology in the commercial and residential sector has not progressed as rapidly as with the larger boilers, primarily because of the smaller emission reduction potential. However, it is known that some emission reduction is economically possible in the commercial and residential sectors.

Oil desulfurization to reduce SO_2 emissions is a well-developed technology although no facilities exist in Canada. Residual (heavy) oil can be readily desulfurized to 0.5%S and light oils to 0.3%S. The cost varies with the type of crude oil and increases with the degree of desulfurization.

The main role for desulfurized oil with respect to the acid deposition problem would be to reduce emissions from large urban areas and to reduce emissions from oil-fired power plants.

C.5.1 Industrial Combustion Units

As in the utility boiler sector, a variety of control strategies can be used to reduce sulfur oxide emissions. These strategies include low-sulfur fuel, wet or dry FGD and fluid-bed combustion. Low-sulfur coal and hydro desulfurization of fuel oil can be used to reduce SO_x emissions to about 1.2 $lb/10^6$ Btu and 0.2 $lb/10^6$ Btu, respectively. Although FGD can lower potential sulfur oxide emissions by up to 90%, there are no units in operation at present in Canada. Fluid-bed combustion can achieve a 70-85% SO_2 reduction and about a 70% reduction in NO_x at operating costs competitive with FGD. The capital cost of the fluid-bed boiler will exceed that of a conventional coal combustion system.

Combustion modification is the principal method of controlling NO_x emissions. The NO_x emission limits achievable using combustion modification are dependent upon the fuel type (oil, coal, gas) and firing method. Studies are presently being done to delineate the optimum methods available.

The cost of retrofitting industrial boilers is highly variable since space limitations and other restrictions can cause significant differences.

C.5.2 NO_x and SO_2 Control Technologies

The dual-alkali wet flue desulfurization process is the dominant sulfur oxide control technology for industrial boilers. Sodium once-through systems are used in industries such as pulp and paper and textile mills which produce a sodium-containing waste stream (from de-ionizer recharging). There are two commercial installations of the lime spray dryer SO_2 control process. The cost of SO_2 control technology varies as a function of boiler size, load factor, and fuel sulphur content. Thus the uncertainty in capital and annual costs can be large. The capital costs and operating costs shown in Figures C.5.1 and C.5.2 can be in error by as much as ± 40 percent.

Frequent operating or other scheduled shutdowns in some industries could create problems in the operating reliability of some control processes. The disposal of scrubber sludge also presents a problem.

C.5.3 Residential and Commercial Combustion Units

Control technology in these sectors has not progressed as rapidly as for the larger boilers, primarily because of the considerably smaller emission reduction potential for this sector. However, research has estimated that some emission reduction is economically possible for commercial and residential boilers.

Research by the U.S. Environmental Protection Agency has shown that proper maintenance and operation of existing commercial and residential heating units are the most economical means of reducing emissions from these sources. Such practices also provide fuel savings which can potentially offset maintenance cost. Education of owners and operators is the best means of achieving the desired maintenance and operating practices.

In a recent study of home heating units, it was found that by identifying and replacing untuneable units and by tuning the remaining units, smoke could be reduced by 50%, CO by 81%, HC by 90% and filterable particulates by 24%. A recent EPA study indicates that by proper design of residential heating systems, it is possible to achieve a 65% reduction in NO_x emissions, and at the same time, to reach a steady state thermal efficiency of 70 to 80%. The fuel reduction potential was found to be approximately 20 percent. The prototype version of the system has been field-tested, and the above results are from this test.

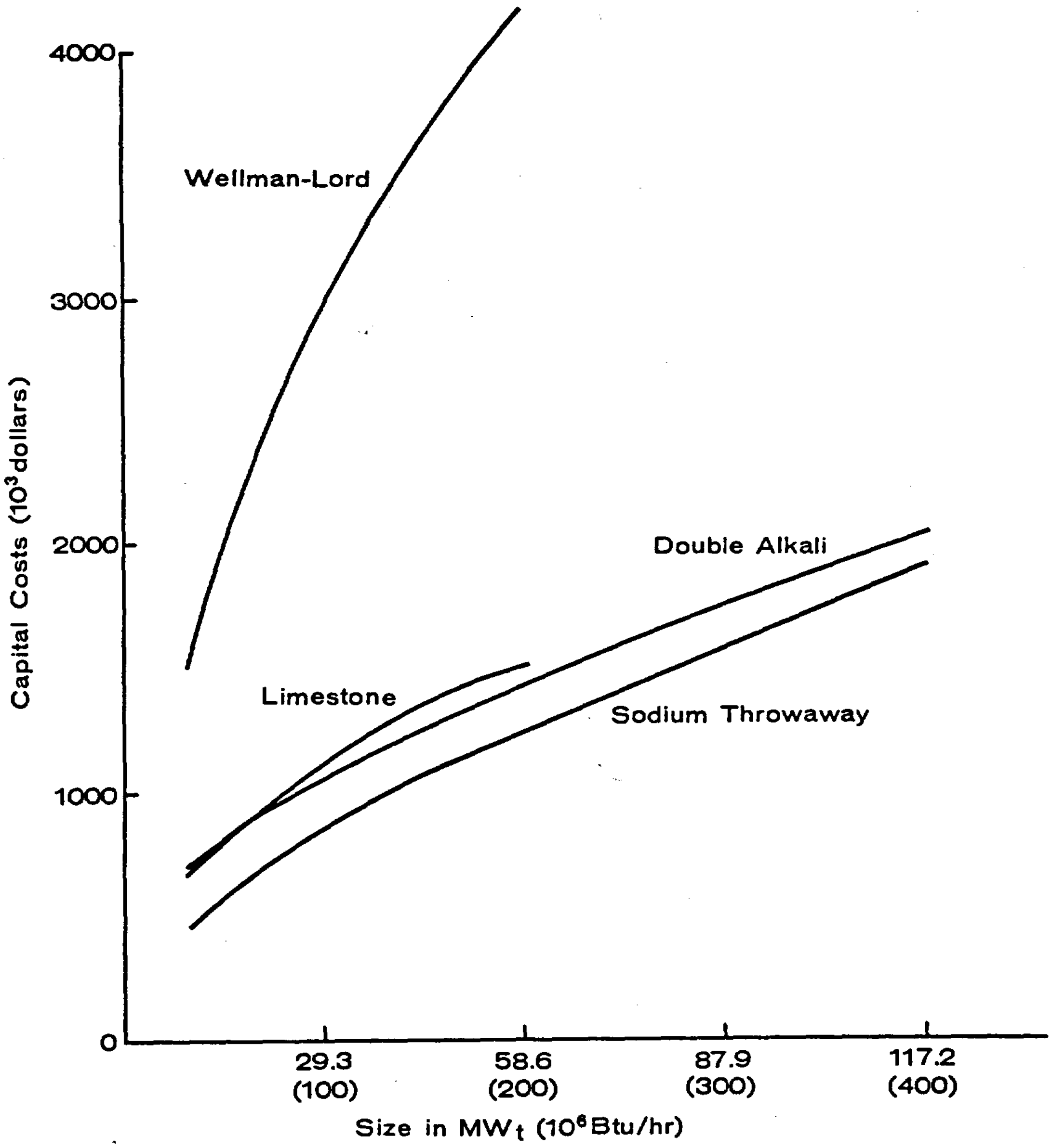


FIGURE C.5.1 FGD CAPITAL COSTS VERSUS UNIT SIZE (3.5% S coal, 90% removal)

Source: Technical Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization
Industrial Environmental Laboratory; U.S. E.P.A., November 1979

Note: Costs are given in U.S. $ (1978).

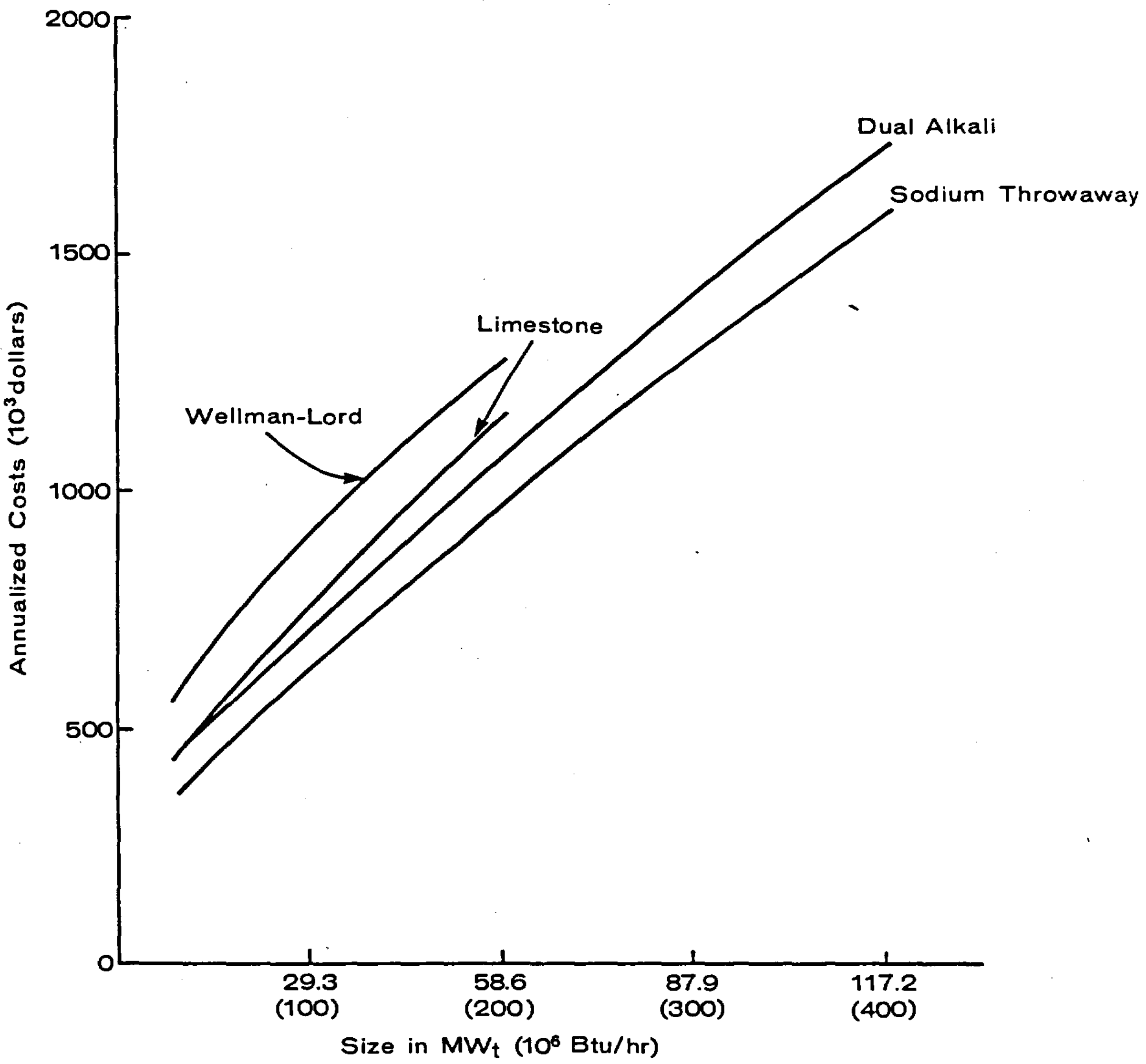


FIGURE C.5.2 FGD ANNUALIZED COSTS VERSUS UNIT SIZE
(3.5% S coal, 90% removal)

Source: Technical Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization
Industrial Environmental Laboratory; U.S. E.P.A., November 1979

Note: Costs are given in U.S. $ (1978).

C.6 INCINERATORS

This sector contributes only very minor amounts (less than 1%) of the sulfur and nitrogen oxides to the nationwide emissions of these pollutants in both Canada and the U.S. Because this source sector represents such a small portion of the aggregate emissions, it is not treated in depth in this report.

C.6.1 Description

Muncipal incinerators emit significant amounts of particulate matter, and lesser amounts of sulfur dioxide and nitrogen oxides to the atmosphere. A large municipal incinerator (1 000 tonnes per day), for example, emits 550 tonnes per year (tpy) of particulates, 300 tpy of sulfur dioxide, and 350 tpy of nitrogen oxides (1). Emissions per tonne of material incinerated tend to be equivalent to or less than other types of controlled incineration, such as controlled air incinerators or sewage sludge incinerators.

Canada

Emissions of SO_2 and NO_x from incineration in Canada are 3 245 tpy and 5 094 tpy respectively. Large incinerators are located in Quebec City, Montreal, Toronto and Hamilton. The emissions of SO_2 and NO_x are a small part of overall Canadian emissions and incineration is not considered to be of significance in the acid rain problem.

There are no hazardous waste incinerators operating in Canada. There is one to come on stream in the Montreal area.

United States

As a generalization, much of the municipal solid waste incineration is centered in the Great Lakes and New England areas while hazardous waste incineration is limited by comparison but is likely to be more ubiquitous.

Estimated emissions of NO_x from solid waste disposal in the U.S. indicate a decrease from about 0.6 million tpy in 1968 (AP-84), to 0.3 million tpy in 1970, to a current level of about 0.1 million tpy (draft criteria document for NO_x, 6/79) because of a reduction in the amount of waste burned. Air pollution control systems currently applied to such incinerators or those likely to be required in the future do not generally remove appreciable amounts of SO_x and NO_x.

C.6.2 Control Options

Control techniques for particulate emissions from incinerators are fairly advanced; however, little, if anything, has been done to reduce sulfur dioxide or nitrogen oxide emissions. Given the relatively low concentration of sulfur in municipal refuse and the low operating temperature of municipal incinerators and consequently low NO_x production compared to fossil-fuel combustion, it would be impractical to attempt to achieve significant reduction in these emissions. The EPA control techniques document for nitrogen oxides suggests alternative disposal methods (e.g., landfill) as the only practical control technique for nitrogen oxides from incineration. There are no United States new source performance standards (NSPS) for incineration facilities that might come on line in the future.

REFERENCES

1. EPA Publication AP-42, "Compilation of Air Pollutant Emission Factors", third edition, August 1977.

C.7 PULP AND PAPER INDUSTRY

C.7.1 Description

This sector contributes a relatively small portion of SO_2 and NO_x to the nationwide emission of these pollutants in both countries. In Canada, less than 2% of the SO_2 and 1% of the NO_x comes from this sector. In the U.S., the contribution is less than 1% for both pollutants. Because this source sector represents such a small contribution to the aggregate emissions, it is not treated in depth as are the major sources.

United States

It is estimated that total SO_x and NO_x emissions from process operations are approximately 157 000 and 45 000 tonnes per year respectively, from about 400 mills. The combustion of fossil fuels for the production of additional steam and power in this industry sector (addressed in Section B.5) contributes an additional 720 000 and 180 000 tonnes per year of SO_x and NO_x respectively. There are no other significant acid rain precursor emissions or direct acidic emissions from this industry sector. Since this industry is not expected to undergo major expansions during the balance of this century, its relatively minor contribution to the total transboundary air pollution problem is unlikely to be altered.

As regards the geographical distribution of pulp and paper facilities, about one third are located in the northeastern region, about one quarter are in the Pacific northwest, and the balance are widely dispersed. The low gross emissions of SO_x, together with the wide geographic distribution of the mills and the expectation that no significant expansion of this industry will occur, indicate that transboundary transport of acid rain precursor emissions from the pulp and paper industry is of secondary importance.

Canada

It is estimated that total SO_x and NO_x emissions from process operations are approximately 88 000 and 13 000 tonnes per year respectively, from 114 mills. The combustion of fossil fuels for the production of additional steam and power in this industry sector contributes an additional 144 000 and 45 000 tonnes per year of SO_x and NO_x respectively. These emissions are split roughly 80/20 between eastern Canada and British Columbia, It is anticipated that a current federal-provincial modernization program will reduce existing emissions. Similar to the U.S., no significant expansion of production capacity is anticipated in the near term. These factors indicate, as in the U.S., that transboundary transport of acid rain precursor emissions from the pulp and paper industry is of secondary importance.

D. PRELIMINARY INFORMATION ON EMISSIONS OF PRIMARY SULFATES, VOLATILE ORGANIC COMPOUNDS AND METTALIC ELEMENTS

D.1 SULFATES

Emissions of gaseous sulphur oxides from anthropogenic sources are known to result in the formation of sulfate particulate matter and free acids, and these species usually account for a large fraction of the ambient aerosol. Although it is recognized that these same species may be emitted directly from various sources, it generally has been assumed that such primary emissions account for a relatively small fraction of the total anthropogenic contribution to the atmospheric loading and deposition rates for these compounds.

The fine particulate matter and aerosols containing these acidic constituents, whether they be of primary or secondary origin, can be transported long distances before being deposited by either wet or dry deposition processes. Thus, there is a need for accurate data on the quantity and characteristics of anthropogenic source emissions in order to evaluate the potential contribution of primary sulfates to the acid deposition problem.

D.1.1 United States

Prelimininary estimates of primary sulfate emissions for the U.S. were developed for calendar year 1980. The source data used to estimate these emissions were largely the same as those used to estimate 1980 SO_2 emissions. Thus, the task of estimating primary sulfate emissions only required the identification of emission factors for primary sulfates, so that emission estimates could be calculated.

Emission factors for primary sulfates are not generally available from the standard literature references. Compilation of Air Pollutant Emission Factors (AP-42) contains practically no information relevant to sulfate emission rates except for limited data for fuel combustion sources. The draft of AP-42 Supplement 13 contains newly updated data for primary sulfate emissions from combustion sources. Additional data are contained in AP-42 background files. The draft report Anthropogenic Sources and Emissions of Primary Sulfates in Canada, prepared for Environment Canada by the Ontario Research Foundation, was found to be the most complete collection of information on primary sulfate emission factors. This report contains information obtained from Canadian sources, but also relies upon the standard air pollution literature, EPA reports, and EPA data bases as sources of information. Available data from AP-42 were found to be basically consistent with the data in the foundation report. Therefore, for the purposes of consistency with the Canadian estimates of primary sulfate emissions and the lack of other available information, primary sulfate emission factors derived from the foundation report were used for most source categories. The emission factors used, expressed as a percent of total SO_2 emissions, are given in Table D.1.1.

Estimates of total and acidic primary sulfate emissions are presented in Tables D.1.2 through D.1.4. Due to the lack of complete emission factor information, this data should be regarded as preliminary estimates. Improved emission factors are needed to refine these emission estimates.

Table D.1.1
Primary Sulfate Emission Factors

Source Category	Total Sulfate	Acid Sulfate	Reference
Primary Copper Smelters	1.8% of SO_2	1.35% of SO_2	ORF
Primary Lead Smelters	2% of SO_2	NA	ORF
Primary Zinc Smelters	5% of SO_2	NA	ORF
Primary Aluminum Smelters	0.5% of SO_2	0.5% of SO_2	ORF
Iron/Steel Sintering	2% of SO_2	None	ORF
Coke Plants	8.2% of SO_2	8.2% of SO_2	ORF
Sulfuric Acid Plants	0.1 lb/ton H_2SO_4	0.1 lb/ton H_2SO_4	ORF
Kraft Pulp Mills	(1)	None	ORF
Sulfite Pulp Mills	(2)	None	ORF
Cement Plants	(3)	None	ORF
Gypsum Plants	(4)	None	ORF
Natural Gas Plant Flares	0.5% of SO_2	0.5% of SO_2	ORF
Sulfur Recovery Claus Plants	1% of SO_2	1% of SO_2	Assumed
Catalytic Cracking Units	15 lb/10^3 bbl Feed	7.5 lb/10^3 bbl Feed	ORF
Electric Utilities			
Coal	1.2% of SO_2	1% of SO_2	ORF
Resid. Oil	5.75% of SO_2	3.75% of SO_2	ORF
Dist. Oil	8.2% of SO_2	4.1% of SO_2	Assumed
Non-utility Coal	1.6% of SO_2	1.36% of SO_2	ORF
Industrial Oil	8.2% of SO_2	4.1% of SO_2	ORF
Commercial Oil	9% of SO_2	7.3% of SO_2	ORF
Residential Oil	10.8% of SO_2	8.4% of SO_2	ORF
Highway Vehicles	(5)	(5)	AP-42, ORF
Railroads	2% of SO_2	1.7% of SO_2	ORF
Resid. Oil Vessels	8% of SO_2	4% of SO_2	Assumed
Other Off-highway Diesel/Dist. Oil	2% of SO_2	2% of SO_2	Assumed
Other Off-highway Gasoline	1% of SO_2	1% of SO_2	Assumed

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[1] Total sulfate emissions for kraft pulp mills estimated as 85% of NEDS total particulate emissions from kraft recovery boilers.

[2] Total sulfate emissions from sodium-base sulfite mills estimated as 70% of NEDS SO_2 emissions; for calcium-base sulfite mills estimated as 25% of NEDS SO_2 emissions

[3] Total sulfate emissions from cement kilns estimated as 5.6 lb/ton of cement on an uncontrolled basis. Average particulate control efficiency from NEDS data assumed to apply in order to calculate actual emissions.

[4] Total sulfate from gypsum plants estimated as 56% of NEDS actual particulate emissions.

[5] Total sulfate emissions for highway vehicles all estimated as acid sulfate. For LDV and LDT categories, emission factors for catalyst equipped and non-catalyst equipped vehicles were weighted according to estimated national VMT for catalyst and non-catalyst equipped vehicles. Calculated results were that for LDV an estimated 5.5% of SO_2 is emitted as sulfate, and forLDT an estimated 3.2% of SO_2 is emitted as sulfate. For HDG, it was estimated that 1% of SO_2 is emitted as sulfate, and for HDD an estimated 2% of SO_2 is emitted as sulfate.

TABLE D.1.2
Estimated Emissions of Primary Sulfates in the United States
(Metric Tonnes/Year)

State	Electric Utilities	Non-utility Combustion	Non-ferrous Smelters	Trans-portation	Other Sources	State Total
Alabama	6 140	3 350	0	510	7 940	17 940
Alaska	160	180	0	60	320	720
Arizona	1 100	430	12 610	230	250	14 620
Arkansas	950	1 830	0	240	1 120	4 140
California	4 530	4 000	0	4 550	4 110	17 190
Colorado	950	1 200	0	240	450	2 840
Connecticut	1 710	2 810	0	170	0	4 690
Delaware	1 340	1 540	0	90	420	3 390
Dist. of Columbia	300	660	0	30	0	990
Florida	25 280	7 190	0	2 030	3 450	37 950
Georgia	8 640	2 590	0	780	3 010	15 020
Hawaii	2 300	640	0	120	110	3 170
Idaho	0	410	1 150	90	440	2 090
Illinois	13 630	5 270	0	810	3 650	23 360
Indiana	16 810	7 310	0	540	7 100	31 760
Iowa	2 610	1 330	0	270	550	4 760
Kansas	1 570	820	0	330	810	3 530
Kentucky	10 720	1 360	0	340	1 170	13 590
Louisiana	1 350	6 010	0	1 510	9 420	18 290
Maine	850	4 480	0	140	3 480	8 950
Maryland	4 130	3 070	0	650	1 340	9 190
Massachusetts	13 730	4 480	0	370	3	18 580
Michigan	7 440	3 380	1 170	1 850	3 450	17 290
Minnesota	2 210	2 190	0	380	930	5 710
Mississippi	3 370	3 760	0	850	1 900	9 880
Missouri	12 760	1 550	530	470	490	15 800
Montana	330	1 820	1 350	120	580	4 200
Nebraska	540	200	0	230	20	990
Nevada	550	90	3 270	70	160	4 140
New Hampshire	2 090	810	0	50	1 140	4 090
New Jersey	2 350	5 870	0	1 110	1 320	10 650
New Mexico	1 130	110	1 040	210	660	3 150
New York	15 120	20 930	0	1 780	2 090	39 920
North Carolina	4 790	7 040	0	470	1 400	13 700
North Dakota	1 290	480	0	100	150	2 020
Ohio	23 980	6 020	0	870	5 620	36 490
Oklahoma	410	450	0	300	2 700	3 860
Oregon	40	1 890	0	500	1 910	4 340
Pennsylvania	17 770	10 940	140	1 220	11 390	41 460
Rhode Island	270	670	0	50	0	990
South Carolina	3 020	4 000	0	290	630	7 940
South Dakota	320	150	0	80	5	550
Tennessee	10 160	2 120	0	430	1 770	14 480
Texas	4 210	5 500	1 980	4 210	15 370	31 270
Utah	440	830	70	140	1 370	2 850
Vermont	30	390	0	40	0	460
Virginia	4 180	6 710	0	870	2 470	14 230
Washington	850	2 800	1 300	880	2 470	8 300
West Virginia	10 360	2 050	0	170	1 920	14 500
Wisconsin	5 020	2 690	0	390	2 470	10 570
Wyoming	1 310	1 020	0	140	960	3 430
TOTAL	255 140	157 420	24 610	32 370	114 490	584 020

TABLE D.1.3
Estimated Emissions of Primary Sulfates in the United States
Acid Sulfates
(Metric Tonnes/Year)

State	Electric Utilities	Non-utility Combustion	Non-ferrous Smelters	Trans-portation	Other Sources	State Total
Alabama	5 100	1 950	0	400	2 190	9 640
Alaska	130	130	0	50	50	360
Arizona	880	290	9 450	220	40	10 880
Arkansas	640	1 060	0	230	70	2 000
California	2 940	2 680	0	3 070	2 310	11 000
Colorado	780	940	0	240	300	2 260
Connecticut	1 120	1 770	0	170	0	3 060
Delaware	930	1 050	0	60	300	2 340
Dist. of Columbia	200	530	0	25	0	760
Florida	17 070	4 060	0	1 320	1 070	23 520
Georgia	7 000	1 410	0	610	40	9 060
Hawaii	1 450	420	0	70	70	2 050
Idaho	0	290	0	90	70	450
Illinois	11 010	3 890	0	770	2 460	18 130
Indiana	13 940	5 220	0	510	6 100	25 770
Iowa	2 150	1 030	0	260	25	3 460
Kansas	1 310	420	0	300	420	2 450
Kentucky	8 890	1 030	0	320	650	10 890
Louisiana	880	4 180	0	920	2 160	8 140
Maine	550	2 750	0	100	2	3 400
Maryland	3 020	2 110	0	450	1 270	6 850
Massachusetts	8 950	3 060	0	330	3	12 340
Michigan	5 870	2 590	880	580	1 810	11 730
Minnesota	1 790	5 710	0	340	320	8 160
Mississippi	2 380	2 500	0	530	730	6 140
Missouri	10 520	2 380	0	440	240	13 580
Montana	260	950	890	110	270	2 480
Nebraska	450	150	0	210	0	810
Nevada	430	70	2 460	60	0	3 020
New Hampshire	1 460	550	0	50	10	2 060
New Jersey	1 690	3 760	0	770	660	6 880
New Mexico	930	70	780	200	590	2 570
New York	10 300	14 450	0	1 220	1 630	27 600
North Carolina	3 960	4 010	0	450	100	8 520
North Dakota	1 070	360	0	90	30	1 550
Ohio	19 810	4 680	0	810	5 030	30 330
Oklahoma	340	300	0	290	1 110	2 040
Oregon	30	1 270	0	370	10	1 680
Pennsylvania	14 340	7 640	0	990	9 630	32 600
Rhode Island	180	460	0	50	0	690
South Carolina	2 380	2 280	0	260	2	4 920
South Dakota	260	120	0	80	0	460
Tennessee	8 410	1 440	0	410	120	10 380
Texas	3 300	1 300	970	2 730	7 580	15 880
Utah	360	490	50	130	690	1 720
Vermont	20	280	0	40	0	340
Virginia	2 920	4 370	0	650	100	8 040
Washington	700	1 780	980	600	330	4 390
West Virginia	8 590	1 430	0	160	1 880	12 060
Wisconsin	4 140	8 040	0	360	130	6 670
Wyoming	1 090	620	0	120	460	2 290
TOTAL	196 960	108 320	16 460	23 620	53 060	398 400

TABLE D.1.4
Estimated Primary Sulfates Emissions in the United States
(Metric Tonnes/Year)

	Total Sulfates			Acid Sulfates		
State	Kraft Pulp Mills	Petroleum Refining	Iron & Steel	Kraft Pulp Mills	Petroleum Refining	Iron & Steel
Alabama	5 620	70	1 900	0	40	1 830
Alaska	240	80	0	0	50	0
Arizona	80	0	0	0	0	0
Arkansas	970	90	0	0	60	0
California	570	2 750	480	0	1 780	480
Colorado	0	100	250	0	50	240
Connecticut	0	0	0	0	0	0
Delaware	0	400	0	0	280	0
Dist. of Columbia	0	0	0	0	0	0
Florida	2 220	10	0	0	0	0
Georgia	2 590	30	0	0	20	0
Hawaii	0	110	0	0	60	0
Idaho	370	0	0	0	0	0
Illinois	0	2 650	930	0	1 540	870
Indiana	0	1 600	5 300	0	910	5 170
Iowa	0	0	0	0	0	0
Kansas	0	750	0	0	420	0
Kentucky	240	530	350	0	290	350
Louisiana	5 760	3 250	0	0	1 870	0
Maine	3 150	0	0	0	0	0
Maryland	20	50	1 220	0	40	1 220
Massachusetts	0	0	0	0	0	0
Michigan	320	360	1 770	0	50	1 760
Minnesota	230	520	0	0	320	0
Mississippi	1 020	400	0	0	250	0
Missouri	0	240	90	0	150	90
Montana	80	440	0	0	260	0
Nebraska	0	10	0	0	0	0
Nevada	0	0	0	0	0	0
New Hampshire	1 120	20	0	0	10	0
New Jersey	0	1 020	0	0	620	0
New Mexico	0	140	0	0	80	0
New York	0	240	1 490	0	150	1 490
North Carolina	1 190	10	0	0	4	0
North Dakota	0	150	0	0	30	0
Ohio	0	990	4 460	0	550	4 450
Oklahoma	60	1 970	0	0	1 110	0
Oregon	1 870	10	0	0	10	0
Pennsylvania	500	2 240	8 500	0	1 280	8 340
Rhode Island	0	0	0	0	0	0
South Carolina	600	0	0	0	0	0
South Dakota	0	0	0	0	0	0
Tennessee	1 630	20	50	0	10	50
Texas	940	9 740	440	0	5 720	390
Utah	0	460	410	0	260	410
Vermont	0	0	0	0	0	0
Virginia	1 360	120	0	0	70	0
Washington	1 140	560	0	0	330	0
West Virginia	0	50	1 850	0	40	1 830
Wisconsin	820	50	100	0	30	100
Wyoming	0	730	0	0	420	0
TOTAL	34 710	32 960	29 590	0	19 170	29 070

D.1.2 Primary Sulfates

In Canada

Primary sulfate emissions inventory for the base year 1978 was prepared under contract for Environment Canada by Ontario Research Foundation (1). The major constituents considered for this inventory were:

1) Particulate sulfates comprised of metallic sulphates and/or neutral sulfate salts;

2) Gaseous and condensed sub-micron particles of sulfuric acid; and

3) Gaseous sulfur trioxide.

Emission data for primary sulfates were obtained from a number of sources. The majority of the information was extracted from published scientific literature. Source test data were available for some sectors and were obtained through contacts with personnel in industry and provincial government agencies. Available data generated through source testing at Canadian plants were used in preference to published emission factors in all available cases.

In general, sulfate emission data in the literature were reported as a ratio of total sulfates to total sulfur oxides or total sulfur dioxide. As a result, these $SO_4^=$ to SO_2 ratios were used together with the sulfur dioxide inventory methodology outlined in Appendix 2, to derive emission factors for total sulfate emissions.

For sectors emitting only particulate sulfates, particulate emission data developed by Environment Canada (2) were used in conjunction with the chemical analysis of particulate emissions as reported in an unpublished study (3) prepared under contract for Environment Canada. Information regarding SO_3/H_2SO_4 emissions was generally available as a ratio to total sulfates and was used to derive emission factors for the acidic fraction.

Primary sulfate emissions as total $SO_4^=$ and acid $SO_4^=$ are shown in Tables D.1.5 and D.1.6, respectively.

REFERENCES

1. Anthropogenic Sources and Emissions of Primary Sulfates in Canada, January 1982, unpublished Document prepared for Environment Canada by the Ontario Research Foundation.

2. Environment Canada, Air Pollution Control Directorate, (Unpublished Information).

3. A Nationwide Inventory of Anthropogenic Sources and Emissions of Primary Five Particulate Matter, March 1981, Unpublished Document prepared for Environment Canada, by SNC/GECO Canada Inc. and Ontario Research Foundation.

TABLE D.1.5
Canadian Emissions of Primary Sulfates (as $SO_4^=$) - 1978 - (tonnes)

	SECTOR										
	INDUSTRIAL PROCESSES						Fuel Combustion (Stationary Sources)				
PROVINCE	Sulfate Pulping	Non-ferrous Smelters	Gypsum Processing	Petroleum Refining	Natural Gas	Other	Utility	Non-utility	Transp.	Misc.	Total
Newfoundland	------	------	322	-----	-----	34	741	2 937	73	Neg	4 107
Prince Edward Island	------	------	-----	-----	-----	-----	177	239	21	Neg	437
Nova Scotia	2 260	------	177	186	-----	405	3 729	5 443	121	Neg	12 321
New Brunswick	3 764	624	219	53	-----	46	4 013	4 464	107	Neg	13 290
Quebec	8 455	11 207	2 418	521	-----	1 397	102	29 605	815	6	54 526
Ontario	7 561	10 102	3 660	319	2	1 503	6 245	17 416	1 095	12	47 915
Manitoba	426	10 665	725	32	-----	158	32	757	230	14	13 039
Saskatchewan	1 669	------	435	21	1	101	450	673	415	14	3 779
Alberta	1 473	------	1 306	59	1 631	1 140	423	1 363	695	68	8 158
British Columbia (Includes Yukon & NWT)	25 776	941	1 677	113	542	167	6	4 902	512	7	34 643
TOTAL	51 384	33 539	10 939	1 304	2 176	4 951	15 918	67 799	4 084	121	192 215

* Neg. = Negligible

TABLE D.1.6
Canadian Emissions of Acid Sulfates (as $SO_4^{=}$) - 1978 - (tonnes)

	SECTOR										
	INDUSTRIAL PROCESSES						Fuel Combustion (Stationary Sources)				
PROVINCE	Sulfate Pulping	Non-ferrous Smelters	Gypsum Processing	Petroleum Refining	Natural Gas	Other	Utility	Non-utility	Transp.	Misc.	Total
Newfoundland	------	------	----	-----	-----	13	482	1 750	73	---	2 318
Prince Edward Island	------	------	----	-----	-----	-----	115	185	21	---	321
Nova Scotia	------	------	----	102	-----	249	2 493	3 817	120	---	6 781
New Brunswick	------	------	----	38	-----	36	2 656	3 023	106	---	5 859
Quebec	------	2 572	----	293	-----	170	66	20 564	811	---	24 476
Ontario	------	5 894	----	232	2	580	4 955	12 316	1 089	---	25 068
Manitoba	------	1 210	----	19	-----	78	26	591	228	---	2 152
Saskatchewan	------	------	----	13	1	53	372	523	413	---	1 375
Alberta	------	------	----	33	1 631	1 009	351	1 308	689	---	5 021
British Columbia (Includes Yukon & NWT)	------	39	----	75	542	48	4	3 351	510	---	4 569
TOTAL	-------	9 715	----	805	2 176	2 236	11 520	47 428	4 060	---	77 940

* Neg. = Negligible

D.2 Volatile Organic Compounds (VOC)

An inventory of VOC for the base year 1978 was prepared under contract for Environment Canada by the Environmental Applications Group Limited (1). For the U.S., 1980 total VOC emission estimates were obtained from reports of the National Emissions Data System (NEDS). VOC are defined as any organic species which when released to the atmosphere, can remain long enough to participate in gas phase photochemical reactions. More specifically, two definitions of VOC have been used in the development of this inventory:

1) organics with vapour pressure greater than 0.1 mm of Hg at standard conditions (20°C and 760 mm Hg) can be considered VOC; and

2) organics with boiling points between 160°C to 300°C can be considered VOC.

For Canada, the inventory was prepared from data obtained in the literature, primarily fom the U.S. EPA publication entitled <u>Volatile Organic Compound (VOC) Species Data Manual</u>, EPA-450/4-80-015. The information from this report combined with emission data on total VOC prepared by Environment Canada (2) was used to develop emission factors for specific volatile organic classes and compounds. In many cases, quantification of specific organic compounds was not possible. Consequently, emissions were quantified in terms of major classes of organic compounds as shown in Table D.2.1.

For the U.S., the breakdown of VOC emissions into their respective chemical categories is based on information found in the following publications: <u>Volatile Organic Compounds (VOC) Species Data Manual</u>, EPA-450/4-80-015; <u>Compilation of Air Pollutant Emission Factors</u>, AP-42; <u>Compilation of Air Pollutant Emission Factors</u>, AP-42, Suplement 13; <u>Air Pollutant Emission Factors for Military and Civil Aircraft</u>, EPA-450-3-78-117; and <u>Air Pollutant Emission Factors - Final Report</u>, TRW, Contract No. CPA 22-69-119.

The emissions summaries are shown in Tables D.2.2 to D.2.5 for Canada and the United States.

Table D.2.1

Volatile Organic Compound Classes

Compound Class Description	Example
Methane	----------
Paraffins	Ethane Propane Hexane
Olefins	Ethylene Propylene Butene
Aromatics	Benzene Toluene Styrene
Carbonyls	Aldehydes Ketones
Oxygenated	Alcohols Esters Organic acids
Sulfur containing	Mercaptans Dimethyl disulfide Dimethyl sulfide
Halogenated	Halogenated olefins and paraffins Halogenated aromatics
Others	Terpenes Polynuclear aromatics Nitrogen containing compounds Oxygen-nitrogen containing compounds Unidentified organic compounds

TABLE D.2.2

Canadian Emissions of Volatile Organics - 1978 - Tonnes

By Chemical Class

SECTOR	PARAFFINS/ ALKANES	OLEFINS/ ALKENES	AROMATICS	CARBONYLS	METHANE	OXYGENATED H.C.	SULPHUR CONTAINING H.C.	HALOGENATED H.C.	OTHER H.C.	TOTAL
INDUSTRIAL PROCESSES										
Sulphate Pulping	---------	4 049	-----	-----	-----	903	8 128	-------	-------	13 080
Crude Oil Production	27 810	-----	24	-----	1 619	---	-----	-------	-------	29 453
Petroleum Refining	127 060	3 848	7 258	182	18 528	95	-----	-------	747	157 718
Natural Gas Processing	585	-----	-----	-----	5 313	---	-----	-------	-------	5 898
Plastics & Petrochemicals	1 328	52 510	6 439	-----	-----	7 448	-----	5 504	127 651	200 880
Others	132	473	232	-----	731	3 749	40	-------	1 502	6 859
SUBTOTAL	156 915	60 880	13 953	182	26 191	12 195	8 168	5 504	129 900	413 888
STATIONARY FUEL COMBUSTION										
Utilities	2 548	610	78	306	1 285	---	-----	-------	104	4 931
Non-utilities	12 719	-----	1 948	4 502	19 072	174	-----	-------	1 225	39 640
Fuel Wood Combustion	7 118	6 775	8 712	2 211	8 951	20 373	-----	-------	3 356	57 496
SUBTOTAL	22 385	7 385	10 738	7 019	29 308	20 547	-----	-------	4 685	102 067
TRANSPORTATION										
On-Road Gasoline	300 579	150 524	127 942	22 856	39 283	---	-----	-------	35 888	677 072
Off-Road Gasoline	15 588	15 813	12 459	2 626	4 245	---	-----	-------	5 140	55 871
Diesel Engines	32 226	7 808	2 231	6 476	2 336	---	-----	-------	2 019	53 096
Others	27 349	15 145	8 986	5 060	3 282	160	1	-------	4 098	64 081
SUBTOTAL	375 742	189 290	151 618	36 998	49 146	160	1	-------	47 145	850 120
SOLID WASTE INCINERATION										
Incineration	211	144	12	176	145	70	-----	-------	268	1 026
Wigwam Burners	3 737	3 555	4 572	1 161	4 700	10 694	-----	-------	1 762	30 181
SUBTOTAL	3 948	3 699	4 584	1 337	4 845	10 764	-----	-------	2 030	31 207
MISCELLANEOUS										
Gas & Diesel Marketing	27 108	13 122	2 222	-----	-----	---	-----	-------	191 993	234 445
Surface Coating	51 720	-----	11 864	20 819	-----	42 575	-----	617	834	128 429
General Solvent Use	11 718	-----	8 090	1 166	-----	18 649	-----	31 650	1 152	72 425
Forest Fires	9 182	8 736	11 236	2 780	11 545	26 351	-----	-------	4 330	74 160
Others	9 931	3 193	3 572	1 496	19 060	8 402	47	19 362	2 280	67 343
SUBTOTAL	109 659	25 051	36 984	26 261	30 605	95 977	47	51 629	200 589	576 802
TOTAL	668 649	286 305	217 877	71 817	140 095	139 643	8 216	57 133	384 349	1 974 084

TABLE D.2.3

Canadian Emissions of Volatile Orgaincs by Province - 1978 - Tonnes

SECTOR	NFLD	P.E.I.	N.S.	N.B.	QUEBEC	ONTARIO	MAN.	SASK.	ALBERTA	B.C.	TOTAL
INDUSTRIAL PROCESSES											
Sulphate Pulping	---	---	275	870	2 009	2 538	165	367	660	6 196	13 080
Crude Oil Production	172	---	2 312	2 030	1 234	29	183	2 945	19 837	711	29 453
Petroleum Refining	2 121	---	11 596	10 144	56 105	40 830	2 848	6 011	16 612	11 451	157 718
Natural Gas Processing	---	---	---	---	---	22	---	53	5 813	10	5 898
Plastics & Petrochemicals	---	---	732	194	20 834	87 521	4 463	291	80 209	6 636	200 880
Others	46	5	229	91	2 242	2 940	139	161	254	752	6 859
SUBTOTAL	2 339	5	15 144	13 329	82 424	133 880	7 798	9 828	123 385	25 756	413 888
STATIONARY FUEL COMBUSTION											
Utilities	157	10	313	191	211	1 435	129	756	1 303	426	4 931
Non-utilities	143	24	2 138	215	1 870	3 072	307	361	30 384	1 126	39 640
Fuel Wood Combustion	1 490	501	2 764	27 243	27 243	16 110	1 802	2 114	1 382	1 326	57 496
SUBTOTAL	1 790	535	5 215	3 170	29 324	20 617	2 238	3 231	33 069	2 878	102 067
TRANSPORTATION											
On-Road Gasoline	10 968	3 569	22 178	17 795	147 787	230 077	34 963	43 569	76 942	89 224	677 072
Off-Road Gasoline	488	256	847	1 360	1 726	7 765	6 706	13 143	15 985	7 595	55 871
Diesel Engines	942	282	1 523	1 325	9 350	13 095	3 095	7 031	9 872	6 581	53 096
Others	1 578	69	1 798	1 350	10 299	22 108	4 944	3 345	10 329	8 351	64 081
SUBTOTAL	13 976	4 176	26 256	21 830	169 162	273 045	49 708	67 088	113 128	111 751	850 120
SOLID WASTE INCINERATION											
Incineration	4	1	7	6	466	401	78	17	17	29	1 026
Wigwam Burners	76	25	301	629	5 091	2 574	168	328	1 096	19 893	30 181
SUBTOTAL	80	26	308	635	5 557	2 975	246	345	1 113	19 922	31 207
MISCELLANEOUS											
Gas & Diesel Marketing	4 230	1 317	8 250	7 622	57 205	84 118	4 568	12 953	26 681	27 501	234 445
Surface Coating	1 936	437	3 016	2 443	33 721	58 097	3 871	3 473	6 797	14 638	128 429
General Solvent Use	1 757	372	2 610	2 133	19 638	26 033	3 217	2 902	5 789	7 974	72 425
Forest Fires	1 236	53	195	696	969	1 986	6 497	24 434	2 057	36 037	74 160
Others	1 348	286	2 196	2 412	16 920	19 516	2 526	2 255	5 139	14 745	67 343
SUBTOTAL	10 507	2 465	16 267	15 306	128 453	189 750	20 679	46 017	46 463	100 895	576 802
TOTALS	28 692	7 207	63 190	54 270	414 920	620 267	80 669	126 509	317 158	261 202	1 974 084

TABLE D.2.4
National VOC by Chemical Categories - (1000 Tonnes/Year)

	TOTAL	METH	PARFN	OLFNS	AROM	CRBYNL	OXY HC	HLG HC	SUL HC	MISC & OTHER
TRANSPORTATION	8 853.8	882.9	3 127.5	1 985.9	1 754.3	549.4	0.0	0.0	0.0	553.8
HIGHWAY VEHICLE	7 438.0	776.3	2 659.6	1 660.4	1 441.9	450.0	0.0	0.0	0.0	449.8
AIRCRAFT	187.3	0.0	83.4	35.6	48.7	17.7	0.0	0.0	0.0	1.9
RAILROADS	184.7	8.1	79.6	27.2	40.3	22.5	0.0	0.0	0.0	7.0
VESSELS	479.5	60.7	123.1	124.8	98.4	20.7	0.0	0.0	0.0	51.8
OTHER OFF-HWY VEH	564.3	37.8	181.8	137.9	125.0	38.5	0.0	0.0	0.0	43.3
STNRY SRCE FUEL COMB	1 245.6	959.2	90.7	27.5	4.8	27.0	0.0	0.0	0.0	136.4
ELECTRIC UTIL	121.4	63.5	8.9	4.7	0.9	10.7	0.0	0.0	0.0	32.7
INDUSTRIAL	1 019.3	827.6	73.6	22.7	2.9	10.6	0.0	0.0	0.0	81.9
COMM-INST	19.1	6.3	6.1	0.1	1.0	3.7	0.0	0.0	0.0	1.9
RESIDENTIAL	85.8	61.8	2.1	0.0	0.0	2.0	0.0	0.0	0.0	19.9
INDUSTRIAL PROCESSES	12 224.6	261.2	4 065.4	189.5	1 375.3	145.8	2 690.7	1 293.9	0.0	2 202.8
PETROLEUM REFINING	515.2	70.2	341.8	0.3	6.5	31.9	0.0	0.0	0.0	64.5
PTRL PRDT STRG/MKT	1 977.9	15.1	1 146.2	46.6	675.4	0.0	0.0	0.0	0.0	94.6
CHEMICAL MFG	1 170.2	109.5	2.6	115.2	0.1	30.1	46.0	44.6	0.0	822.1
ORGANIC SOLV USE	7 942.1	0.0	2 557.4	0.0	670.8	69.9	2 564.5	1 249.3	0.0	821.2
PRIMARY METALS	117.7	56.0	7.9	27.4	12.4	0.0	0.0	0.0	0.0	14.0
OTHER PROCESSES	501.5	10.4	9.5	0.0	1.1	13.9	80.2	0.0	0.0	386.4
SOLID WASTE DISPOSAL	768.7	318.6	192.6	217.2	30.5	0.0	0.0	0.0	0.0	9.8
MISCELLANEOUS	2 675.6	87.8	616.0	269.7	321.9	12.1	488.7	215.4	0.0	664.0
FOREST WILDFIRES/ PRESCRBD BURNING	894.3	87.8	101.2	227.7	0.0	0.0	0.0	0.0	0.0	477.6
OTHER BURNING	129.0	0.0	42.2	42.0	0.0	0.0	0.0	0.0	0.0	44.8
NON-INDSTL ORGANIC SOLVENT USE	1 652.3	0.0	472.6	0.0	321.9	12.1	488.7	215.4	0.0	141.6
TOTAL EMISSIONS - 1980	25 768.3	2 509.7	8 092.2	2 689.8	3 486.8	734.3	3 179.4	1 509.3	0.0	3 566.8

TABLE D.2.5

State VOC By Source Category - (1000 Tonnes/Year)

	AL	AK	AZ	AR	CA	CO	CT	DE	DC	FL	GA	HA	ID	IL	IN
TRANSPORTATION	155.5	18.9	123.7	95.8	928.1	175.2	109.4	23.3	16.1	402.2	212.1	31.0	49.1	391.3	213.6
HIGHWAY VEHICLES	132.5	11.0	106.5	72.2	819.3	154.9	100.9	3.8	13.4	329.8	186.3	23.5	36.5	324.2	180.5
OFF-HIGHWAY VEHICLES	22.9	7.9	17.2	23.6	108.8	20.3	8.5	3.8	2.7	72.4	25.8	7.5	12.6	67.1	33.1
STNRY SRCE FUEL COMB	23.9	4.7	13.2	14.1	73.1	20.2	2.6	0.6	0.4	17.9	12.3	0.8	5.2	16.1	15.4
INDUSTRIAL PROCESSES	207.1	15.6	40.7	103.1	1004.6	84.6	199.6	32.5	10.6	248.2	212.5	17.0	20.6	567.7	335.0
PETROLEUM REFINING	21.7	0.0	0.1	0.6	91.0	1.6	0.0	5.5	0.0	0.0	0.1	0.5	0.0	11.0	3.9
PETROL PRDT STRG/MKT	19.6	12.9	2.0	12.5	223.8	16.0	14.3	3.8	0.3	55.8	35.8	8.3	4.8	79.6	34.7
CHEMICAL MFG	16.2	0.0	0.8	11.5	16.2	0.3	2.0	3.8	0.0	13.6	1.3	0.0	0.2	17.2	3.0
ORGANIC SOLVENT USE	111.9	2.6	37.3	78.5	656.2	62.0	179.0	19.3	10.3	177.9	173.5	8.1	15.5	447.6	255.2
OTHER PROCESSES	37.7	0.1	0.5	0.7	17.4	4.7	4.3	0.1	0.0	0.9	1.8	0.1	0.1	12.3	38.2
SOLID WASTE DISPOSAL	19.6	2.1	15.0	8.2	87.1	12.4	6.9	1.2	0.8	10.2	13.3	3.5	7.3	37.5	25.2
MISCELLANEOUS	71.8	3.2	31.3	24.0	227.8	29.8	19.7	3.8	4.1	119.2	79.1	15.9	68.7	71.4	34.5
NON-INDSTL ORGANIC SOLV USE	23.5	2.4	16.5	13.9	143.0	17.5	18.8	3.6	3.9	58.1	32.8	5.9	5.7	69.0	33.2
OTHER SOURCES	48.3	0.8	14.8	10.1	84.8	12.3	0.9	0.2	0.2	61.1	46.3	10.0	63.0	2.4	1.3
STATE VOC EMISSIONS TOTAL	477.9	44.5	223.9	245.9	2320.7	322.2	338.2	61.4	32.0	797.7	529.3	68.2	150.9	1084.0	623.7

TABLE D.2.5 (continued)

State VOC By Source Category - (1000 Tonnes/Year)

	IA	KS	KY	LA	ME	MD	MA	MI	MN	MS	MO	MT	NE	NV	NH
TRANSPORTATION	127.3	113.4	138.4	160.4	38.4	148.1	204.5	315.9	183.3	89.6	216.8	49.9	82.0	40.0	26.6
HIGHWAY VEHICLES	90.7	83.9	115.1	126.3	30.1	128.0	186.0	264.6	142.4	72.4	176.0	37.8	57.8	33.2	24.1
OFF-HIGHWAY VEHICLES	36.6	29.5	23.3	34.1	8.3	20.1	18.5	51.3	40.9	17.2	40.8	12.1	24.2	6.8	2.5
STNRY SRCE FUEL COMB	7.7	90.7	19.5	112.6	3.6	5.6	5.1	22.6	11.1	40.5	10.4	5.8	5.6	0.6	1.4
INDUSTRIAL PROCESSES	117.3	81.2	196.0	374.4	48.8	149.9	273.0	573.5	215.4	119.8	338.6	23.8	74.8	16.1	54.7
PETROLEUM REFINING	0.0	7.1	7.6	50.8	0.0	6.2	0.0	12.4	5.4	14.5	1.9	8.1	0.1	0.0	0.0
PETROL PRDT STRG/MKT	13.8	17.9	28.7	55.2	17.4	24.4	26.8	60.4	45.1	18.3	30.3	6.1	10.3	6.7	5.7
CHEMICAL MFG	12.2	3.1	39.1	192.0	0.2	3.0	6.0	3.2	5.0	1.4	55.3	0.1	0.5	0.0	0.0
ORGANIC SOLVENT USE	89.5	51.6	100.3	64.0	29.8	108.3	223.8	480.2	157.1	82.4	249.9	9.2	63.6	9.2	48.8
OTHER PROCESSES	1.8	1.5	20.3	12.4	1.4	8.0	16.4	17.3	2.8	3.2	1.2	0.3	0.3	0.2	0.2
SOLID WASTE DISPOSAL	16.6	11.5	11.1	12.8	8.7	7.1	17.2	41.5	16.6	12.1	23.3	5.4	8.1	2.5	3.6
MISCELLANEOUS	18.6	24.9	26.6	56.4	7.6	26.6	37.2	57.7	27.7	41.7	34.6	59.6	11.5	7.1	5.8
NON-INDSTL ORGANIC SOLV USE	17.7	14.3	22.1	25.5	6.8	25.5	34.8	56.1	24.7	15.3	29.8	4.7	9.5	4.9	5.6
OTHER SOURCES	0.9	10.6	4.5	30.9	0.8	1.1	2.4	1.6	3.0	26.4	4.8	54.9	2.0	2.2	0.2
STATE VOC EMISSIONS TOTAL	287.5	321.7	391.6	716.6	107.1	337.3	537.0	1011.2	454.1	303.7	623.7	144.5	182.0	66.3	92.1

TABLE D.2.5 (continued)

State VOC By Source Category - (1000 Tonnes/Year)

	NJ	NM	NY	NC	ND	OH	OK	OR	PA	RI	SC	SD	TN	TX
TRANSPORTATION	271.8	83.4	438.3	232.2	40.6	393.9	147.0	121.2	369.9	37.5	119.1	43.6	181.3	639.3
HIGHWAY VEHICLES	248.8	70.2	389.1	198.5	23.5	346.1	125.2	99.2	324.4	35.1	98.3	25.9	155.0	526.0
OFF-HIGHWAY VEHICLES	23.0	13.2	49.2	33.7	17.1	47.8	21.8	22.0	45.5	2.4	20.8	17.7	26.3	113.3
STNRY SRCE FUEL COMB	5.2	40.2	14.1	9.8	2.3	34.4	72.7	13.3	34.5	0.5	5.1	0.5	24.4	350.1
INDUSTRIAL PROCESSES	398.0	35.6	534.0	303.8	11.0	619.0	151.7	94.7	731.1	62.0	318.4	14.0	268.1	1754.6
PETROLEUM REFINING	4.1	1.6	0.0	0.0	1.5	6.3	20.2	0.0	12.2	0.0	0.0	0.0	1.5	153.7
PETROL PRDT STRG/MKT	91.4	20.1	52.1	35.6	3.4	60.6	59.7	18.5	90.3	6.6	20.4	5.0	29.3	453.0
CHEMICAL MFG	12.5	0.0	0.1	34.3	0.0	16.8	6.3	2.0	10.9	0.4	19.7	0.0	58.0	575.8
ORGANIC SOLVENT USE	287.4	13.1	368.7	224.9	6.0	509.4	62.5	64.8	531.7	54.9	262.4	8.6	173.1	446.6
OTHER PROCESSES	2.6	0.8	113.1	9.0	0.1	25.9	3.0	9.4	86.0	0.1	15.9	0.4	7.7	125.5
SOLID WASTE DISPOSAL	12.8	3.8	38.9	20.3	4.2	45.9	7.0	12.3	24.1	2.7	15.5	5.9	19.1	30.2
MISCELLANEOUS	47.3	13.8	114.1	51.2	5.1	68.3	42.4	58.5	75.1	6.0	40.4	37.4	37.6	309.8
NON-INDSTL ORGANIC SOLV USE	44.6	7.9	106.4	35.5	4.0	65.4	18.2	15.9	71.9	5.7	18.6	4.2	27.6	86.1
OTHER SOURCES	2.7	5.9	7.7	15.7	1.1	2.9	24.2	42.6	3.2	0.3	21.8	33.2	10.0	223.7
STATE VOC EMISSIONS TOTAL	735.1	177.0	1139.4	617.3	63.2	1161.5	420.8	300.0	1234.7	108.7	498.5	101.4	530.5	3084.0

TABLE D.2.5 (continued)

State VOC By Source Category - (1000 Tonnes/Year)

	UT	VT	VA	WA	WV	WI	WY
TRANSPORTATION	79.5	15.7	200.6	196.9	58.4	190.7	47.4
HIGHWAY VEHICLES	69.1	12.7	172.9	167.7	47.9	151.4	35.5
OFF-HIGHWAY VEHICLES	10.4	3.0	27.7	29.2	10.5	39.3	11.9
STNRY SRCE FUEL COMB	8.6	0.8	8.1	10.9	13.2	8.1	21.1
INDUSTRIAL PROCESSES	39.0	16.8	226.0	125.0	44.1	229.3	23.7
PETROLEUM REFINING	4.8	0.0	1.0	6.5	0.0	0.5	11.4
PETROL PRDT STRG/MKT	8.8	2.6	34.4	24.9	8.0	31.2	10.6
CHEMICAL MFG	0.0	0.1	20.7	0.5	2.2	1.3	0.0
ORGANIC SOLVENT USE	24.7	13.6	153.6	81.6	27.6	194.1	1.5
OTHER PROCESSES	0.7	0.5	16.3	11.5	6.3	2.2	0.2
SOLID WASTE DISPOSAL	5.6	2.8	12.4	18.8	7.6	22.2	3.4
MISCELLANEOUS	16.8	3.2	35.6	103.6	16.7	29.8	7.2
NON-INDSTL ORGANIC SOLV USE	8.9	3.1	32.2	25.0	11.7	28.4	2.8
OTHER SOURCES	7.9	0.1	3.4	78.6	5.0	1.4	4.4
STATE VOC EMISSIONS TOTAL	149.5	39.3	482.7	455.2	140.0	480.1	102.8

REFERENCES

1. National Inventory of Anthropogenic Sources and Emissions of Organic Compounds, March 1981, Unpublished Document prepared for Environment Canada by the Environmental Applications Group Limited.

2. Environment Canada, Air Pollution Control Directorate, Data Analysis Division, (Unpublished Information).

D.3 METALLIC ELEMENTS

D.3.1 United States

Preliminary estimates of emissions of selected metals were calculated based on data available from EPA contract reports and other published references. National estimates are presented for each metal. Emission factors for the selected metals are generally based on limited data. For some source categories, no emission factors are available. Control efficiency data specifically for metals are usually not available either. For sources where a control efficiency is needed, it was assumed that a control efficiency for total particulate emissions was applicable to metallic elements. Because of the lack of data to compile detailed emission inventories for metals, assumptions such as these are necessary. As a result, the emissions estimates shown in Table D.3.1 should be regarded only as preliminary order of magnitude estimates. References used to calculate emission estimates for each metal are identified below:

Arsenic: Emission estimates for 1974 were taken directly from the report Human Exposures to Atmospheric Arsenic, SRI International, Sept. 1978 (EPA Contracts 68-01-4314 and 68-02-2835).

Barium: Emission factors were obtained from National Inventory of Sources and Emissions of Barium - 1969, W. E. Davis & Associates, May 1972 (EPA report APTD-1140). These emission factors were applied to industrial process production data reported in the 1977 Minerals Yearbook (U.S. Bureau of Mines, Dept. of the Interior) and coal and oil consumption data calculated from U.S. Dept. of Energy references, to calculate 1977 estimates.

Cadmium: Estimated emissions for 1979 were obtained directly from Survey of Cadmium Emissions Sources, GCA Corporation, September 1981 (EPA-450/3-81-013).

Chromium: Estimated emissions for 1970 reported in Reviews of the Environmental Effects of Pollutants: Chromium (EPA-600/1-78-023) were identical to data reported in National Emissions Inventory of Sources and Emissions of Chromium, GCA Corporation, May 1973 (EPA-450/3-74-012). These data were updated to 1977 using updated production data from 1977 Minerals Yearbook.

Copper: Emission factors were obtained from National Inventory of Sources and Emissions of Copper - 1969 (APTD-1129). These emission factors were applied, using the same references as noted above for barium, to calculate 1977 emission estimates.

Lead: Emission estimates were taken directly from computer printout reports from the Hazardous and Trace Emissions System (HATREMS), EPA, OAQPS, Research Triangle Park, NC. Current HATREMS reports represent 1979. HATREMS uses source production data from NEDS, together with its own set of emission factors (AEROS Manual of Codes, Update 4, EPA-450/2-76-005-4) to calculate emissions.

Manganese: Estimated emissions for 1978 were obtained directly from Human Exposure to Atmospheric Concentrations of Selected Chemicals, SAI, Inc.

Mercury: Emission factors from Emission Factors for Trace Substances, EPA, OAQPS, December 1973 (EPA-450-2-73-001) were applied to industrial production and fuel consumption data, from the references cited above for barium, to calculate 1977 estimated emissions.

Nickel: 1978 estimated emissions were taken directly from Human Exposure to Atmospheric Concentrations of Selected Chemicals by SAI, Inc.

Selenium: Emission factors were obtained from National Inventory of Sources and Emissions of Selenium - 1969 (APTD-1130). Production data were obtained as noted above for barium, to calculate 1977 emission estimates.

Vanadium: 1977 emission estimates were calculated using the same references as noted for mercury.

Estimated emissions for these metals are summarized in the following tables. These emissions estimates are discussed briefly for each metal below:

Arsenic: Emissions occur mainly from primary non-ferrous metal smelting operations, where arsenic is present in metallic ores. Arsenic is also recovered as a smelter byproduct in Washington state. Emissions from the application of agricultural chemicals that contain arsenic are also significant.

Barium: The largest source of barium emissions is in ore mining and processing. About 75% of production is in Nevada. Production of barium chemicals and end uses of these chemicals also contribute significantly to emissions.

Cadmium: Cadmium emissions occur largely from fuel combustion and non-ferrous smelting operations. Cadmium is found in both coal and oil. Combustion of fuel oils produces about 62% of fuel combustion emissions, coal 34%, and kerosene, jet fuel and gasoline 4%.

Chromium: The largest source of chromium emissions is in ferro-alloy refining. Fuel combustion, production of refractory brick, and iron and steel mills represent the next largest sources of chromium emissions.

Copper: Primary copper smelters account for over 60% of estimated copper emissions. Remaining emissions occur from a variety of other sources.

Lead: About 75% of lead emissions result from transportation sources, primarily due to consumption of leaded gasoline. The relative market share of leaded gasoline has been decreasing, and consequently, lead emissions also are expected to decrease.

Manganese: Manganese emissions occur largely from the iron and steel industry, ferro-alloy refining, and iron foundries. Significant emissions also result from coal combustion, largely from electric utilities. About 50% of national emissions are estimated to occur in Middle Atlantic (NY, NJ, PA) and East North Central (IL, IN, OH, MI, WI) states.

Mercury: The largest category of mercury emissions is estimated to be from the application of paints. Mercurial compounds are used as mildew proofing agents and as a paint preservative in latex paints. Emissions from waste disposal of products containing mercury are crudely estimated. This estimate roughly accounts for mercury lost from waste electrical equipment, catalysts, and amalgams where reclamation to recover secondary mercury is not performed.

Nickel: Nickel emissions occur mainly from fuel combustion. Nickel present in trace amounts in fuel oils accounts for 98% of fuel combustion emissions, with the remainder from coal combustion.

Selenium: Selenium emissions occur mainly from fuel combustion and glass manufacturing. Emissions from fuel combustion are about 58% from coal and 42% from fuel oil.

Vanadium: About 98% of vanadium emissions occur from fuel combustion. In turn, about 97% of emissions from fuel combustion are accounted for by residual oil use. The vanadium content of residual oils imported from Venezuela is particularly high. Nearly all Venezuelan residual oil imported goes to the U.S. East coast.

TABLE D.3.1
Selected Metals Emissions for the United States, by Category (Tonnes)

Heavy Metals	Industrial Processes	Fuel Combustion	Trans-portation	Incineration	Misc.	TOTAL
Arsenic	4 720	540	NEG	NEG	2 830	8 090
Barium	5 315	810	NEG	NEG	2 705	8 830
Cadmium	202	455	80	48	NEG	785
Chromium	3 225	670	NEG	40	NEG	3 935
Copper	3 623	660	NEG	155	180	4 618
Lead	4 706	835	43 240	3 363	NEG	52 140
Manganese	13 737	2 575	NEG	NEG	NEG	16 312
Mercury	60	98	NEG	8	330	496
Nickel	885	8 545	810	NEG	NEG	10 240
Selenium*	122	211	NEG	NEG	NEG	333
Vanadium	245	14 235	NEG	4	NEG	14 484

* Non-metallic element

D.3.2 Canada

Emission estimates for various metals have been summarized by source category and province in Tables D.3.2 and D.3.3 respectively. These estimates are taken from inventories prepared by the Air Pollution Control Directorate of Environment Canada, and most are available as published documents. The inventories represent a mix of base years. Detailed information on each of the inventories can be found in the following reports:

National Inventory of Sources and Emissions of Beryllium (1970)
- APCD 73-5 (October 1973)

National Inventory of Sources and Emissions of Vanadium (1972)
- APCD 75-3 (September 1975)

National Inventory of Sources and Emissions of Arsenic (1972)
- APCD 75-5 (January 1976)

National Inventory of Sources and Emissions of Zinc (1972)
- APCD 76-1 (June 1976)

National Inventory of Sources and Emissions of Cadmium (1972)
- APCD 76-2 (June 1976)

National Inventory of Sources and Emissions of Selenium (1976)
- EPS 3-AP-77-8 (September 1977)

National Inventory of Sources and Emissions of Copper and Nickel (1976)
- EPS 3-AP-81-4 (August 1981)

National Inventory of Sources and Emissions of Antimony, Barium, Bismuth, Chromium, Cobalt and Tin (1976)
- to be published

National Inventory of Sources and Emissions of Mercury (1978)
- to be published

National Inventory of Sources and Emissions of Lead (1978)
- to be published

TABLE D.3.2

Canadian Emissions of Selected Metals, by Category (Tonnes)

Heavy Metal	Industrial Processes	Fuel Combustion	Transportation	Incineration	Miscellaneous	Total
Beryllium	Neg	7	---	Neg	---	7
Vanadium	24	1 848	---	1	1	1 874
Manganese	5 972	17	Neg	7	14	6 010
Arsenic	3 654	34	Neg	1	5	3 694
Cadmium	416	86	3	3	Neg	508
Zinc	6 341	134	795	124	2	7 396
Selenium*	130	47	1	1	Neg	179
Copper	2 318	91	5	79	302	2 795
Nickel	974	596	55	54	90	1 769
Antimony	52	2	3	4	---	61
Barium	102	118	10	16	---	246
Bismuth	61	19	Neg	2	---	82
Cobalt	78	13	1	2	1	95
Chromium	69	54	12	102	7	244
Tin	43	39	Neg	85	2	169
Mercury	20	9	---	2	9	40
Lead	4 726	30	11 658	301	60	16 775

* Non-metallic element

TABLE D.3.3

Canadian Emissions of Heavy Metals, by Province (Tonnes)

Province	Beryllium	Vanadium	Manganese	Arsenic	Cadmium	Zinc	Selenium*	Copper	Nickel	Antimony	Barium	Bismuth	Cobalt	Chromium	Tin	Mercury	Lead
Newfoundland	Neg	68	2	1	1	19	Neg	37	38	Neg	3	Neg	1	5	2	1	269
P.E.I.	Neg	25					Neg	--	10	Neg	1	---	Neg	1	Neg	Neg	65
Nova Scotia	1	273	217	19	27	585	3	20	100	1	24	1	1	10	2	1	515
New Brunswick	Neg	215					1	13	64	11	5	Neg	1	6	13	1	607
Quebec	1	1 203	1 369	377	382	2 926	34	366	223	7	29	31	6	49	15	9	5 052
Ontario	1	52	3 887	2 650	65	1 468	98	1 861	1 147	12	59	33	72	134	89	8	3 911
Manitoba	1	4	99	461	18	1 054	26	179	32	2	14	7	7	8	3	12	1 901
Saskatchewan	2	6	348	5	3	810	5	36	29	Neg	30	3	1	6	1	2	810
Alberta	1	11	67	6	2	239	11	11	15	1	27	7	3	9	2	3	1 162
B.C.	Neg	13	20	16	9	250	2	161	75	26	56	1	3	15	43	4	1 979
Yukon-N.W.T.	Neg	Neg	1	153	2	44	Neg	107	33	Neg	Neg	Neg	1	4	1	Neg	502
CANADA	7	1 870	6 010	3 688	509	7 395	180	2 791	1 765	60	248	83	96	247	171	41	16 773

NOTE: Sub-totals may not add up to the grand total due to rounding and the contribution from smaller sources.

* Non-metallic element

E. CONSTRAINTS ON AND BOUNDARY OF ANALYSIS OF EMISSION PROJECTIONS

A variety of methods and models are used to project emissions from each sector. While underlying assumptions for each are basically compatible, differences may exist in terms of applied regional growth rates. No attempt has been made to integrate the analysis across sectors within a state. The accuracy of the emission projections presented in Section C for each sector depend upon several critical factors. These include the ability to describe the existing source population, which serves as the basis for projections of future energy use, the ability of the methodology to capture likely future fuel use and emission behavior, and the values of the assumptions that underlie the projections. Following is a discussion of these limits on the ability to model various sectors and the effects on projected emission values within each sector. In addition, for the electric utility sector, this section will compare the current updated fuel use and resulting emission projections with previous estimates presented in the February, 1981 Interim Report. Thus, the range in national emission projections that result from different methodologies and assumptions and the uncertainty in the projections can be seen.

E.1 ELECTRIC UTILITY SECTOR

i) Comparison with Previous Emission Projections

Table E.1 presents a comparison of current estimates for national emissions with previous emission estimates and estimates of utility fuel use and demand growth using other models as presented in the Phase I report. The projections are taken from the following sources.

1) U.S. Department of Energy "Energy Projections to the Year 2000", DOE/PE-0029, July, 1981.

2) ICF Incorporated "Executive Summary, Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions", May, 1981.

3) ICF Incorporated "Regional Summaries, Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions", June, 1981

4) Teknekron Research, Inc. "Electric Utility Emissions: Control Strategies and Costs", Draft Report, April, 1981.

DOE's projected energy use is based upon the Fossil 2 model* which used a system dynamic modeling technique to represent the balance between national energy supply and demand. The model

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*See "Fossil 2 Energy Policy Model Documentation: General Structures of the Fossil 2 Model", U.S. Dept. of Energy, Assistant Secretary for Policy and Evaluation, Oct., 1980, on which this discussion is based.

consists of both supply and demand sectors, which interact by exchanging information on fuel demand, availability and price to balance supply and demand. Overall demand is a function of gross national product, average energy price and average energy availability. Fuels are substituted according to relative costs to the consumer.

On the supply side, demand for each fuel is compared with available production capacity to determine average prices. Finally, estimates of investments needed by each industry, given fuel and capital costs, are compared to funds available. Available investments are then allocated to various production technologies according to relative marginal costs.

The Interim Report presented emissions projections from two models: the Utility Simulation Model (USM), developed and operated by Teknekron Research, Incorporated (TRI), and the Coal and Electric Utilities Model (CEUM) developed and run by ICF Incorporated. Both models are capable of projecting future energy use, by fuel type, for the electric utility industry, given a baseline energy scenario and assumed costs of oil and gas fuels and future generation costs. The models also calculate the cost of emission controls, and relative cost effectiveness of emissions control on the basis of a dollar per ton of collected pollutant.

The two models differ in basic design.* Briefly, CEUM uses a coal supply component to provide coal to satisfy the demand of both utility and non-utility customers at least cost, using a linear program which minimizes total national delivered costs to the customer. The model employs constraints to represent factors such as SIP limits, long term coal contracts, transportation and transmission capacities and planned future power plant additions. CEUM groups current plants into representative unit categories as a starting point for the analysis. The USM is a series of interconnected modules, which rely on current data bases of electricity demand, financial market conditions, fuel supply, and existing and planned units. USM begins with a data base including all existing power plants and allows these units to determine least cost compliance strategies. Then, the model simulates the joint operation of various types of generating units and capacity classes owned by all utilities within a state. Finally, USM scales up to future demand by simulating plant additions according to utility announced plans and specified percentages of plant types. Both models can simulate the choice of different coal supply sources and concomitant transportation paths.

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*This discussion is derived from two reports:

- ICF, Inc. "Scenario Specifications: Alternative Strategies for Reducing Utility SO_x and NO_x Emissions", June, 1981.
- Teknekron Research Inc, "Electric Utility Emissions: Control Strategies and Costs", DRAFT, April, 1981.

The 1980 emissions estimates were updated on a unit-by-unit basis and include an updated energy scenario. Thus, a new set of state-level utility emissions projections was developed as described in Section C.

As can be seen from Table E.1, previous analyses presented a wide range in emission projections, despite the use of many similar input assumptions by both models projecting utility emissions. There is no simple explanation for this considerable difference, which perhaps serves to illustrate the range of uncertainty inherent in projections of utility emissions. Factors which may contribute to the differences include assumptions about operating behavior of plants subject to state level emission limits, the extent to which coal will be used, the use of plant specific emission rates by USM as opposed to generic limits by plant category by CEUM, and differences in costs. USM predicted much higher levels of scrubbed capacity than CEUM. Finally, the analysis using CEUM assumed all power plants would be forced from natural gas to oil by 2000, because of the Power Plant and Utility Regulatory Policy Act, thus more oil would be consumed and higher levels of sulfur emitted. This is balanced somewhat by assumptions of higher nuclear capacity by CEUM.

The current set of emission projections falls below other projections. Lower overall electricity growth rates result in lower total fuel demand. A lower rate of nuclear additions (and thus higher relative coal use) partially offsets the decrease in emissions from lower growth rates. Hydroelectric power, geothermal and "other" sources of power are projected to remain about constant, as are oil and gas, thus coal bears a larger relative share of the baseline generation.

An important comparison for purposes of state level emissions projections is the relative fossil fuel shares which can indicate something about the speed with which conversions of oil capacity to coal occur, and about the use of natural gas by utilities in each region. Each of these factors will significantly affect state-level emission projections.

Table E.2 presents total fossil fuel used, and percentage share of total fossil fuel by fuel type for each region as found in the EHPA and ICF projections. Generally, in 1990 similar percentages of various fossil fuel usage is seen by EHPA and CEUM with the exception of the West South Central region where more relative coal use is projected by EHPA, and the Pacific region where less coal use is projected. For 2000, EHPA projects lower oil use in New England and higher coal use in the Pacific. Overall, there is substantial agreement in type of fossil fuel used to meet fossil fuel demand.

ii) Sensivity of Methodology to Changes in Input Assumptions

To demonstrate the sensitivity of the projections, a number of other cases were run to examine the effect of changes in assumption values on emissions and fuel use projections. These are illustrated in Table E.3. These sensitivity runs demonstrate the sensitivity of the national projections to the values of these assumptions. We can expect the sensitivity of the state level projections to be even greater. In particular, regional projections will vary even more significantly depending on the extent to which the regional distribution of plants by age of plant and the type of planned additions differ from the national distributions of these parameters. For example, certain regions have even greater percentages of older (pre 1956) coal plants than the national average of 15% of capacity; thus changes in plant life assumptions are expected to be more significant for those regions. The effect of changes in values of assumptions for regional or state emissions has not been evaluated for this report.

Table E.4 presents the results of changes in the values of these assumptions. As expected, changes in SO_2 emissions for all cases for year 1990 are small, while emissions in Year 2000 are considerably higher for the higher growth case, offset by the higher nuclear growth. The most significant change in SO_2 emissions is found if a shorter lifetime for coal plants is assumed (45 years) because existing plants are replaced with new plants with tighter controls. Thus, in 2000, SO_2 emissions drop by 10% from the base case.

Higher growth rates also have a significant effect on NO_x emissions, increasing them substantially as new plants produce higher levels of NO_x.

E.2 INDUSTRIAL BOILERS AND PROCESS HEATERS

The primary factor determining SO_2 emissions from the industrial boiler population is the extent to which coal is consumed in boilers. Consumption, in turn, is determined by the differential between the price of coal and the price of oil and gas, and how willing manufacturers are to invest in new coal-fired equipment. The modeling of this latter point - willingness to invest - is probably the weakest part of the IBM, which chooses least cost alternatives. It appears, based on a comparison with other models, and observations of the current economic atmosphere, that IBM may overestimate industrial coal consumption in 1990 and 2000 and subsequently overestimate SO_2 emissions.

Demand for new industrial equipment has not grown at recent historical rates. Actual demand for new boilers, including coal-fired boilers, is less than what is anticipated in the model. The causes of this discrepancy may be, in addition to slow growth of new steam needs, a tendency to maintain older boilers beyond a normal retirement age, and manufacturers investing in ventures with a higher rate of return than the introduction of new coal-fired technology at plants.

It is useful to compare energy demand projected in the industrial models with that projected by the 1981 NEPP. (Table E.5)

Fuel shares in the two models are different especially in the year 2000. NEPP shows less coal use and increased use of gas in the industrial sector. However, assumptions differ in the models. NEPP assumes a boiler lifetime of 30 years, whereas IBM assumes a 45 year lifetime. Fuel prices are also different: NEPP assumes a world oil price in 2000 of $63.70 (1980$ per barrel); IBM assumes $47.60. Conservation is also an important factor. NEPP assumes that industrial energy demand will grow by an average of 1.2 percent per year until 2000; IBM assumes a growth rate of 1.9 percent per year.

The major drawback in projecting regionalized emissions is the uncertainty in knowing the extent to which industrial activity will shift from region to region and when this shift will occur. This problem is inherent in all the emission projections that use OBERS and BEA data to reflect future demographic change. Although these projections are uncertain, any attempt at an improved forecast would be based in part on judgmental analysis concerning regional growth and technological change and would be subject to the same criticism. The basic conclusion is that whatever uncertainty is engendered when projecting emissions at the national level is magnified when trying to regionalize the results.

E.3 PRIMARY NON-FERROUS SMELTERS

Uncertainty in smelter SO_2 projections derives mainly from two sources:

1) Future changes in SIP
2) Smelter closings

Proposals to change the method by which compliance of smelters is determined could add approximately 91 000 metric tonnes per year SO_2 to the national projection specified in Section C. In addition, the three smelters assumed to close by 1990, may not close at all, adding another 273 000 metric tonnes per year. Therefore, the range of projected SO_2 smelter emissions would be from approximately 600 000 metric tonnes per year to a maximum of about 1 000 000 metric tonnes per year.

E.4 RESIDENTIAL/COMMERCIAL

The Residential/Commercial sectors have historically been declining in terms of SO_2 and NO_x emissions. This is due mainly to a switch away from coal to gas and electricity. Emission projections are based on a continuation of this pattern and on the assumption of a high degree of conservation.

Uncertainties involve estimates of fuel prices which will spur conservation and again, on forecasts of demographic change from which state-by-state projections are derived.

E.5 INDUSTRIAL PROCESSES

Future changes in technology, growth in industrial activity, and accuracy of emission factors are the major constraints to projecting emissions from the Industrial Process sector. Although the updating of emissions factors is an ongoing process, no improved values for this sector are available at this time.

E.6 TRANSPORTATION

The MOBILE2 model projects NO_x emissions based on assumptions concerning the effectiveness of future controls for mobile sources. The greatest uncertainty concerns NO_x emission factors and deterioration rates of future vehicles. Deterioration rates for 1981 model year cars are speculative due to their low mileage. Emission factors for future cars are even more uncertain.

Growth rates for VMT depend, to a large extent on changes in fuel price that affect demand for gasoline and travel. Elasticity of gasoline demand with respect to price has not been determined. Further uncertainty has to do with identifying how VMT change in vehicle classes that specifically affect high pollution levels. Rates at which dieselization will occur in the vehicle population are also somewhat speculative.

The SEAS program which projects Transportation SO_2 is limited by assumptions concerning growth in VMT. Trace levels of sulfur in gasoline are not likely to change.

Both models are limited by the methodology by which national emissions were regionalized. Regionalization was accomplished primarily through population breakdowns and historical patterns of inter-city travel.

TABLE E.1

Comparison of Base Case Study Results

	Utility Baseline	DOE (Mid Case)	USM (BAS)	CEUM (Base Case)
SO_2 Emissions (million tons)				
1990	17.5	N/A	17.9	18.9
2000	17.9	N/A	17.2	20.1
NO_x Emissions (million tons)				
1990	7.5	N/A	7.5	8.9
2000	9.6	N/A	9.2	10.5
Fuel Consumption (quads)				
1990				
Coal	15.9	16.7	18.6	16.8
Oil	2.2	1.8	2.2	2.1
Gas	2.7	2.9	1.7	3.9
Nuclear	5.0	7.6	7.1	7.9
Other	3.5	3.8	N/A	3.4
Total	29.3	32.8	29.6[1]	34.1
2000				
Coal	24.1	22.0	25.2	25.2
Oil	1.2	1.1	1.7	3.6
Gas	1.6	2.2	1.3	0.0
Nuclear	7.2	10.6	8.9	10.0
Other	4.6	5.5	N/A	3.6
Total	38.7	41.5	37.1[1]	42.4
Generation (TWhrs)				
1990	2,840	2,800[2]	3,250	3,290
2000	3,740	3,600	4,060	4,110
Average Annual Growth in Electricity Demand %				
1980-1990	2.1	3.0	3.4	3.4
1990-2000	2.7	2.6	2.3	2.3
1980-2000	4.4	2.7	2.8	2.8

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[1] Totals for fossil fuel plus nuclear fuel. Fuel consumption totals for "other" category not available.

[2] DOE begins with low 1980 generation.

Source: See text.

TABLE E.2

Share of Utility Fuel Use by Region - Percent of Fossil Generation by Fossil Fuel Type and Total Fossil Fuel Use

	1990		2000	
	EHPA	CEUM	EHPA	CEUM
New England				
Coal %	47	51	78	68
Oil %	46	47	17	32
Gas %	7	3	5	-
Total (quads)	0.5	0.5	0.7	0.6
Middle Atlantic				
Coal %	69	72	85	82
Oil %	24	20	10	16
Gas %	7	7	5	-
Total (quads)	2.1	2.3	2.2	2.4
East North Central				
Coal %	93	93	96	94
Oil %	5	3	1	6
Gas %	2	4	3	-
Total (quads)	4.2	4.3	5.6	5.9
West North Central				
Coal %	90	92	93	93
Oil %	3	1	3	7
Gas %	7	7	4	-
Total (quads)	1.9	2.1	2.4	2.5
South Atlantic				
Coal %	83	80	92	93
Oil %	13	15	6	7
Gas %	4	6	2	-
Total (quads)	4.0	4.1	5.5	5.1
East South Central				
Coal %	94	92	97	94
Oil %	2	2	1	6
Gas %	4	6	2	-
Total (quads)	1.9	1.9	2.3	2.1
West South Central				
Coal %	56	43	80	78
Oil %	2	3	1	21
Gas %	42	55	19	-
Total (quads)	3.3	4.2	4.4	5.6

TABLE E.2 (continued)

	1990		2000	
	EHPA	CEUM	EHPA	CEUM
Mountain				
Coal %	90	89	96	87
Oil %	2	2	1	4
Gas %	8	9	2	-
Total (quads)	1.6	2.1	2.3	2.8
Pacific				
Coal %	14	26	72	62
Oil %	39	30	14	38
Gas %	46	44	14	-
Total (quads)	1.1	1.3	1.4	1.8

TABLE E.3

Sensitivity Analysis Assumptions

Input Assumptions	Base Case Assumption	Sensitivity Analyses Case	 Assumption
Electricity Growth	1.5% 1981-1985 2.7% 1986-2000	A.1	3.4% 1981-2000
New Baseload Capacity	Current Utility Plans with Coal Beyond Announced Plans	B.1	Nuclear at 20% of Baseload Beyond Plans
		B.2	Case B.1 Plus Growth of Case A.1
Plant Lives	50 Year Coal	C.1	45 Year Coal
RNSPS	Current Regulations and PSD	D.1	RNSPS/BACT Assumed on All Plants On-line After 1981

TABLE E.4

Sensitivity of Utility Emissions Projections to Alternate Assumptions

	1990				2000			
	SO_2 Emission		NO_x Emission		SO_2 Emission		NO_x Emission	
Case	million tons	% of Base	million tons	% of Base	million tons	% of Base	million tons	% of Base
Base	17.5	100	7.5	100	17.9	100	9.6	100
A.1 High Growth	17.9	102	8.2	109	19.1	107	11.8	123
B.1 Increased Nuclear	17.5	100	7.5	100	17.8	99	9.2	96
B.2 High Growth[1] Increased Nuclear	17.9	102	8.2	109	18.7	104	11.0	115
C.1 45 Year Coal Plant Life	17.5	100	7.5	100	16.2	91	9.2	96
D.1 RNSPS	17.0	97	7.5	100	17.3	97	9.5	99
E.1 Capacity Factor for Existing Coal	16.4	94	7.2	96	17.1	96	9.4	98

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[1] Increases nuclear's share of Btu's consumed as follows: 1990-from 17% to 20%, 2000-from 18% to 22%

TABLE E.5

Total Industrial Fossil Fuel Energy Demand (10^{15} Btu)

	IBM plus PHM		NEPP	
	1990	2000	1990	2000
Coal	2.9	6.4	3.3	5.3
Oil	1.5	2.1	2.6	0.6
Gas	8.0	6.6	8.6	9.3
By-products	3.0	3.6	1.8	2.5
Total	15.4	18.7	16.3	17.7

F. RESEARCH ACTIVITIES AND RECOMMENDATIONS FOR FUTURE APPLIED R & D ACTIVITIES

F.1 CURRENT R & D RELATED TO SO_2/NO_X CONTROL

Projects currently underway for the control of sulfur and nitrogen oxides emissions from fuel combustion sources are given in the list below. The projects have been arranged in three groups; namely, sulfur dioxide control, nitrogen oxides control, and combined sulfur dioxide/nitrogen oxides control. More detailed information on the objectives, scope, and funding of the individual projects in each group is presented in Appendix 7.

Sulfur dioxide control:

- Development/evaluation of dry Flue Gas Desulfurization (FGD) technology.

- Research on fundamentals of electrostatic augmentation of fabric filtration and the evaluation and fundamental development of two-stage electrostatic precipitators (for spray-dryer FGD applications).

- Development/demonstration of an adipic acid-enhanced limestone FGD process.

- In-house research and development on flue gas desulfurization (limestone and dual-alkali processes).

- Flue gas desulfurization technology assessment (state-of-the-art technology assessment and technology transfer).

- Coal cleaning assessment (coal washability and other physical coal cleaning techniques).

Nitrogen oxides control:

- Low-NO_X burners (development and demonstration of industrial and utility coal-fired boilers).

- Evaluation of in-furnace NO_X reduction (reburning).

- Heavy oil/low-NO_X burner development and field evaluation. Operation and maintenance of existing NO_X combustion modification equipment.

- Application and assessment of combustion modification for coal-fired stoker boilers (flue gas recirculation/staged combustion).

- Emission control by combustion modification for industrial process combustion equipment (petroleum process heaters, steel furnaces, cement kilns, and glass furnaces).

- Fundamental combustion research.
- Technology transfer through joint EPA/EPRI symposium on stationary combustion NO_x control.

Combined sulfur dioxide/nitrogen oxides control:

- Limestone injection multistage burner (LIMB).
- Bitumen/heavy oil and processed product characterization and end-use assessments.
- Fluidized bed combustion (includes mechanistic and pilot studies, industrial-scale installation, and materials evaluation study).
- Assessment of NO_x and combined SO_x/NO_x control by flue gas treatment technology.
- Assessment of SO_2/NO_x removal from coal flue gases using electron irradiation.
- Assessment of SO_2/NO_x removal from coal flue gas using CuO bed.

F.2 RECOMMENDATIONS FOR FUTURE ACTIVITIES

F.2.1 Applied Research and Development

Sectors that are responsible for the emission of SO_2 and NO_x have been identified in this report including thermal power generation, non-ferrous smelting, industrial/commercial boilers, and mobile sources. The aims of the recommended future R & D activities, highlighted in the sections below, are the further development and refinement of existing new and emerging technologies for the control of SO_2 and NO_x emissions from these sectors.

F.2.1.1 Fossil-Fuel-Fired Electricity

R & D efforts which should be considered include:

1) **Projects Affecting SO_2 Emissions Reduction**

- A project to demonstrate the emission reductions achievable with, and the economics of, the spray dryer FGD process applied to high sulfur coals and low-sulfur western coals. If successfully demonstrated, this process could be appreciatively less costly than lime/limestone FGD from both capital and operating cost standpoints for low to medium sulfur removal efficiencies (50 to 75%). A commercial spray-dryer FGD facility (110-MW Riverside Station of Northern States Power), already in operation, is capable of handling high-sulfur coal, and could be used for testing purposes by the appropriate governmental agency.

- R & D is needed on advanced particulate control concepts that will lower the capital and operating costs associated with spray-dryer SO_2 control. In this regard, the EPA pilot-scale project on electrostatically-enhanced fabric filtration (ESFF) offers excellent potential for materially reducing the size (and cost) of the fabric filter collector associated with the spray-dryer FGD process.

- Adipic acid enhancement of limestone FGD has been demonstrated by EPA at the pilot plant and commercial-scale levels as a technically and economically feasible means of improving SO_2 removal efficiency, as well as improving limestone utilization and process reliability. However, more commercial scale testing is needed on a variety of coals and operating conditions to completely establish this process as a worthwhile tool for SO_2 reduction. Adipic acid enhancement of limestone FGD could permit the burning of high-sulfur coals, i.e., 4-6 percent sulfur, and still achieve substantial SO_2 removal efficiencies (70-90 percent) in retrofit situations at a reasonable cost.

- Evaluation on a bench scale of a coal burning gas turbine.

- Evaluation of blended eastern and western coals to assess emission reductions against the operating performance of the boiler.

ii) Projects Affecting NO_x Emission Reduction

- Long-term demonstration projects on improved control technology for NO_x reduction, e.g. advanced low NO_x burners on pulverized coal boilers, should be conducted on commercial-size units.

- To conduct a full-scale demonstration of the feasibility of burning mixtures of pulverized coal, water, and oil in an oil-fired power plant. This would assist in determining the feasibility of reducing oil consumption without the capital cost of conversion and, in addition, the influence of water in the mixture on flame temperature and the formation of nitrogen oxides.

iii) Projects Affecting Combined SO_2 and NO_x Reductions

- To determine the effectiveness of alkali additives for SO_2 control, as well as the potential for NO_x reduction, in the combustion of mixtures of pulverized coal, water, and oil in an oil-fired power plant.

- Demonstration-scale verification is needed of promising U.S. bench-scale and pilot plant testing of LIMB technology (limestone injection multi-stage burners) for SO_2 and NO_x reduction. Results of EPA-sponsored pilot plant efforts in the U.S. indicate that 50 to 70 percent of sulfur can be removed from a range of low to high sulfur coals with limestone stoichiometries of 2-3.

- Determine the compatibility of various technologies for the control of SO_2 and NO_x emissions.

F.2.1.2 Non-Ferrous Metal Smelters

R&D efforts which should be considered for acid rain mitigation in this area include:

- Identifying and developing practical smelting processes that produce only high-strength SO_2 gas streams amenable to SO_2 fixation.

- The development of more selective mineral dressing processes to eliminate high-sulfur, low-metal-value minerals from the concentrates, thereby upgrading the smelter feed.

- Process/control technology development for the capture of SO_2 emissions from low-concentration SO_2 waste gas streams.

- The development and characterization of new and existing markets for sulfur-containing products (particularly sulfuric acid) recovered from non-ferrous smelters.

- Development and characterization of adipic-acid enhancement of lime scrubbing, citrate scrubbing and dry scrubbing for smelter gases.

- Feasibility studies of alternative pyro-and hydrometallurgical processes.

- Reduction of SO_2 to sulfur by biotechnology or by institutional arrangements (e.g. combine with fuel desulfurization or coal gasification plant to provide source of cheap reductant).

- Performance and evaluation tests of Mitsubishi system.

- Development of improved acid plant operating techniques to improve emission control, including particulate control.

F.2.1.3 Industrial Boilers

R&D efforts which should be considered for acid rain mitigation in this area include:

- Long-term demonstration project on SO_2 reduction using coal-limestone pellets as feed to large stoker-fired boilers.

- The retrofit installation of a spray-dryer FGD system on an industrial boiler (e.g. Argonne National Laboratory 100 000 lb/h steam boiler), to establish the technical and economic feasibility of using this process to control SO_2 emissions from industrial boilers burning high sulfur coal.

- Identify and evaluate methods to remove nitrogen from crude oils in the refining process.

- Evaluate alternative control technologies to remove nitrogen oxides from fuel combustion gases in non-utility fuel boilers.

- Implement demonstration scale projects on improved control technologies for the reduction of emissions of nitrogen oxides.

F.2.1.4 Other Acid Rain Mitigation Areas

- Development of systems/technology to accelerate the reduction of NO_x emissions from existing transportation fields.

- Continuation of long-term efforts to develop alternative and cleaner methods of coal utilization, such as FBC, SRC, coal-liquid mixtures, and coal gasification.

F.2.2 Improvements in Emission Inventories

Emission inventory studies are required to refine and improve existing SO_2 and NO_x emission estimates and to develop new or improved emission estimates for other pollutants.

For SO_2 and NO_x, the principal refinements required include:

- Development of temporal adjustment factors to determine seasonal or monthly emission estimates from existing annual estimates.
- Better spatial resolution of the data to provide emission estimates for areas on a smaller geographical scale than is currently available.
- Use uncertainty estimates to identify special sources and/or source categories, in such a way that improvements in the existing data could lead to the most beneficial improvement in the overall error in the emission inventory.

For improvements in the emission inventories of the other pollutants, it is recommended that research be directed to the following areas:

- Improvements in the accuracy of the emission factors for other pollutants.
- Development of source-inventory methodology to include sources not included in the current emission estimates.
- Collection of more source-specific data, such as trace metal concentration in fuels, and control efficiencies for other selected pollutants.

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- Development of source-inventory methodology to include sources not included in the current emission estimates.
- Collection of more source-specific data, such as trace metal concentration in fuels, and control efficiencies for other selected pollutants.

APPENDIX 1

APPENDIX 1

1.1 TERMS OF REFERENCE

The Terms of Reference contained in the Memorandum of Intent are:

This Work Group will provide support to the development of the "Control" element of an agreement. It will also prepare proposals for the "Applied Research and Development" element of an agreement.

In carrying out its work, the Work Group will:

- identify control technologies, which are available presently or in the near future, and their associated costs;
- review available data bases in order to establish improved historical emission trends for defined source regions;
- determine current emission rates from defined source regions;
- project future emission rates from defined source regions for most probable economic growth and pollution control conditions;
- prepare proposals for the "Applied Research and Development" element of an agreement.

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APPENDIX 2

APPENDIX 2

2. METHODOLOGY FOR CONSTRUCTION OF EMISSIONS INVENTORIES

2.1 INVENTORY METHODOLOGY (SO_2, NO_x): CANADA

A description of the methodologies used in estimating SO_2 and NO_x emissions is given for each of the categories described in Section B.2.

2.1.1 NON-FERROUS SMELTERS

The emission estimates for copper-nickel smelters were provided to Environment Canada by the respective provincial agencies. The estimates are based on monthly mass balances of sulfur in the feed ore and concentrate that are treated, as reported to the provincial authorities by the smelter operators. In the case of Inco, Copper Cliff, a continuous SO_2 monitor measures SO_2 concentrations leaving the superstack. A comparison of the data between the sulphur balance and the monitored concentration indicates variability of less then 10%. In addition, the emissions from INCO's Iron Ore Recovery Plant (IORP), also in Copper Cliff, have been estimated based on a sulfur mass balance.

Emissions from Canada's lead/zinc smelters have been estimated using emission factors calculated from historical questionnaire data collected by Environment Canada (1974) and current production figures obtained from the literature (1). Production data for aluminum smelters (1) were used in conjunction with U.S. EPA derived emission factors (2) to estimate SO_2 and NO_x emissions for most processes in the industry. For the aluminum smelter in British Columbia, emission data were provided by the Pollution Control Branch of the province.

2.1.2 POWER GENERATION BY UTILITIES

For those plants for which data were available for the base year 1980 (i.e. - major thermal power stations east of the Manitoba-Ontario border), sulfur dioxide emissions were determined based on a percentage of the sulfur in the fuel and total consumption of fuel. These data were provided by the utility companies to Work Group 3B.

The sulfur content of the fuels burned are weighted averages of the results of routine fuel analyses carried out, usually on a monthly basis, by the utilities. Percentage of sulfur emitted as sulfur dioxide varied between 95% (Nova Scotia) and 100% (Ontario and New Brunswick).

Nitrogen oxide emissions were estimated using fuel consumption data obtained from the utilities and U.S. EPA derived nitrogen oxides emission factors (2). Ontario Hydro, for most plants, provided actual test values of nitric oxide concentrations in the flue gas. Although it has been assumed that 100% of nitrogen oxides are emitted in the form of nitric oxide, emissions have been reported as NO_2.

Where 1978 emission data have been calculated, some actual plant information was available from provincial agencies, with estimates made using the same methodology as explained above. For smaller plants, such as diesel and gas turbines, total fuel consumption on a provincial basis along with appropriate emission factors were used to calculate both SO_2 and NO_x emissions (2,3).

2.1.3 NON-UTILITY FUEL COMBUSTION

As stated in the introduction, this category covers fuel combustion emissions from industrial, commercial and residential sources. In addition, NO_x emissions from the burning of fuelwood has been included.

1) <u>Residential Fuel Combustion</u> - Fuels considered in this sector include: natural gas, liquid petroleum gases (LPG), light and heavy fuel oils, kerosene and coal. Provincial consumption data by fuel type were available from Statistics Canada (4). Emission factors used were taken from a U.S. EPA publication for both SO_2 and NO_x (2). Canadian sulfur contents for these fuels were used together with the SO_2 emission factor.

2) <u>Commercial Fuel Combustion</u> - The same fuels as were considered for residential fuel combustion are considered here. Commercial establishments are comprised of public administration and other commercial/institutional establishments (as defined by Statistics Canada (4). Emission factors are from the same reference as given in 1) above.

3) <u>Industrial Fuel Combustion</u> - Under this general sector, fuel consumption data and emission factors were generally taken from the same references as for the residential and commercial sectors.

   For the petroleum refining sector, emissions data for fuel combustion were calculated using historical questionnaire data collected by Environment Canada (1974) and current fuel consumption figures.

   Fuel combustion emissions from natural gas plants are essentially only for NO_x. Nitrogen oxide emissions from boilers, heaters and compressors have been calculated using plant fuel consumption data on a provincial basis, together with U.S. EPA emission factors (1,2).

4) Fuelwood Combustion - This sector includes fuelwood burned in residential or commercial furnaces. Production data with internally derived emission factors were used to estimate NO_x emissions (5,6).

2.1.4 MOBILE SOURCES

Gasoline-powered motor vehicles are the most significant sources of NO_x emissions in Canada. An internally developed model was used to calculate NO_x emissions on a nation-wide basis. The sources considered in this sector are: passenger automobiles, light-duty trucks (0-6000 lb), small heavy-duty trucks (6000 - 10 000 lb) and heavy-duty gasoline-powered trucks (10 000 lb +). Various factors considered in the model include: vehicle miles travelled per year (VMT), vehicle registrations, speed distribution, vehicle miles travelled distribution for each vehicle type, and degradation factors. Based on these factors, a NO_x emission factor was developed for each vehicle type and used to estimate emissions. Sulfur dioxide emissions were estimated using vehicle registrations and a U.S. EPA emission factor (2,7).

Diesel-powered motor vehicle NO_x emissions have also been calculated using the model just described. Sulphur dioxide emissions were determined by using an emission factor (2). In addition, there exist other diesel engines, mainly for agricultural construction and other industrial use, which have also been included in this sector. Base quantity consumption data from Statistics Canada (4,7,8) with U.S. EPA emission factors (2) were used to estimate both SO_2 and NO_x emissions for these uses of diesel oil.

Other sectors that have been included under this category are: railways, marine, aircraft, and off-road use of gasoline. The general methodology used in estimating emissions for these sectors was using fuel consumption data with appropriate emission factors (either U.S. or Canadian)(2,4,6,9-14).

2.1.5 PETROLEUM REFINING

Emissions of sulfur dioxide from petroleum refineries' process operations were calculated using historical industry questionnaire data collected by Environment Canada (1974) and current production figures. Nitrogen oxide emissions were calculated using emission factors from a U.S. EPA report (2).

2.1.6 NATURAL GAS PROCESSING

Estimates of emissions of sulfur dioxide from natural gas processing plants in Alberta were provided to Environment Canada by Alberta Environment. These estimates were based on monthly sulfur balance reports submitted by the plant operators to the Energy Resources Conservation Board (ERCB) of Alberta. Nitrogen oxide emissions were determined using production data and emission factors (1,2).

For the province of British Columbia, emission data on sulfur dioxide were obtained under contract for Environment Canada. Sulfur dioxide and nitrogen oxides emissions for plants in Saskatchewan and Ontario have been estimated using production data and emission factors (1,2).

2.1.7 TAR SANDS OPERATIONS

Emission statistics for Alberta's two synthetic crude oil plants were only available for 1979. Production figures for synthetic crude oil were obtained from Statistics Canada (15). Sulfur dioxide emissions for 1979 were determined based on a proration of 1978 emissions obtained from plant sulfur balances, as provided to Environment Canada by Alberta Environment. Nitrogen oxide emissions were calculated using data obtained from Alberta Environment.

2.1.8 OTHER

This category is fairly general in that it covers all sources of SO_2 and NO_x emissions that have not been defined so far in this discussion. These sectors have been combined since their contribution to total SO_2 or NO_x emissions are minor, compared to those categories already discussed. Of all these sources, only one stands out as being somewhat significant relative to all the others: iron ore sintering.

Iron ore was sintered at only one mine site in Canada, the Algoma plant in Wawa, Ontario. Total sinter production and SO_2 emission figures were obtained from the Ministry of Environment for Ontario, who receives monthly sulfur balances from the company.

There are approximately 15 other sectors considered in the inventory that contribute either SO_2 or NO_x emissions. However, the magnitude of these emissions is small enough (approximately 3.0% of total SO_2 and 3.0% of total NO_x) to discuss them generally. Emissions of both SO_2 and NO_x were calculated using either production or consumption data together with emission factors. Production information was obtained from actual plant statistics, from various provincial agencies or federal government statistical publications. Some sectors had available questionnaire data, from which emission factors were derived. These Canadian factors, in addition to U.S. EPA emission factors (2) were used with the reported base quantities.

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13. Statistics Canada, Publication No. 51-002, Air Carrier Operations in Canada, 1978.

14. Statistics Canada, Publication No. 53-218, Road Motor Vehicles - Fuel Sales, 1978.

15. Statistics Canada, Publication No. 26-213, The Crude Petroleum and Natural Gas Industry, 1979.

2.2 INVENTORY METHODOLOGY (SO_2, NO_x): UNITED STATES

The general approach that was used to develop the data relies to the maximum extent possible upon the standard procedures and resources of the NEDS, maintained by EPA at Research Triangle Park, NC. For electric utility, industrial fuel combustion, and industrial process source sectors auxilliary procedures and data sources were used to determine emissions to the highest possible degree of reliability, given the time and resources available to complete this project. For other source sectors, data are derived from NEDS files, updated to best represent calendar year 1980, as appropriate. The following sections discuss the methodology used for each source sector:

2.2.1 ELECTRIC UTILITIES

Emission estimates for electric utilities were derived by E.H. Pechan and Associates, Inc. using U.S. Department of Energy fuel quantity and quality data reported by individual utility companies. This data base is presumed to be the most reliable and consistent set of data available to the U.S. Government.

Information on the quantity of fuel delivered to utilities for the generation of electricity was available for individual plants from Federal Power Commission (FPC) Form 4. It is assumed that the quantity of fuel delivered is equal to the amount consumed over a year. Fuel quality information (fuel sulfur contents) was taken from FPC Form 423. These data files were merged to create a file containing a single data record for each plant with all required data elements.

SO_2 emissions were calculated by simply multiplying the quantity of fuel burned times the percent sulfur times two (two tons of SO_2 per ton sulfur). From bituminous coal fired plants a 5 percent retention of sulfur in ash was assumed, for sub-bituminous coal 15 percent, and for lignite 25 percent. Emission reductions from SO_2 flue gas scrubbing were also accounted for. Information on installed FGD systems, control, efficiency and operating parameters were obtained from EPA Utility FGD Surveys. It was assumed that SO_2 scrubbers are operated continuously at their design efficiency and scrub the fraction of total plant capacity for which they were designed. If a scrubber was installed and operated for only a portion of a full year, then emissions estimates were adjusted to take this into account. A more detailed description of the methodology used to derive 1980 utility SO_2 emissions is provided in a forthcoming report "Estimates of Sulfur Oxide Emissions from the Electric Utility Industry", produced by E.H. Pechan and Associates for EPA's Office of Research and Development.

NO_x emissions were calculated using the fuel quantity data from FPC Form 4, emission factors from AP-42 Supplement 13, information on firing types of specific boilers and as appropriate, applicable NO_x emission limits and/or NO_x control equipment in place. Most of the NO_x reduction is achieved by boilers subject to NSPS requirements. Many of the remaining units subject to NO_x limits are in California. The AP-42 Supplement 13 emission factors are assumed to represent "uncontrolled" emission levels. Implicit in the derivation of these emission factors are assumptions about combustion operating practices, primarily involving excess combustion air. E.H. Pechan and Associates is currently performing additional research to identify current levels of excess air use. New information developed in this manner may be used to refine the existing emission estimates.

Summaries of SO_2 and NO_x emissions from electric utilities on a state-by-state basis were obtained by simply summing appropriate facility emission estimates.

2.2.2 INDUSTRIAL COMBUSTION

For industrial combustion, state-level fuel use totals were obtained from U.S. Department of Energy reports. Emission factors were obtained from AP-42, Supplement 13 draft edition. Fuel sulfur contents were derived as described below for each fuel. It was assumed that any controls applicable to SO_2 and NO_x have a negligible effect on state-level emissions. Hence, all emissions were calculated using AP-42 uncontrolled emission factors.

Coal: State-level coal shipments were obtained from the U.S. DOE report Coal Distribution January-December, 1980 (DOE/EIA-0125(80/4Q). Total shipments were adjusted to exclude the estimated amount of coal consumed by cement plants as described in the discussion of methodology for cement plants. AP-42 emissions factors were weighted to consider the grades of coal shipped to each State (anthracite, bituminous, sub-bituminous, and lignite) and the population of individual types of boilers within each State, based on the distribution of fuel consumed by boiler type as reported in the December 1981 NEDS point source file. Sulfur contents were computed as weighted averages for each State based on the total coal shipments to a state from each DOE coal production district and an average sulfur content of coal shipped from each production district. The latest available sulfur contents of coal shipped from each production district (1978 data) were obtained from the DOE Energy Information Administration.

Oil: State-level distillate and residual oil use was derived from the DOE report Deliveries of Fuel Oil and Kerosene in 1979 (DOE/EIA-0113) (79). 1980 data at the state level were not available when this project was initiated. 1979 data were updated to approximate 1980 totals using update factors derived from the ratio of estimated petroleum supplied for domestic use in 1979 and 1980 for Petroleum Administration for Defense (PAD) districts. These data were calculated from refinery output, pipeline shipments, imports and exports, and other petroleum product movement data reported in the DOE Annual Petroleum Statements for 1979 and 1980 (DOE/EIA-0108(79) and DOE/EIA-0108/80). The final totals were adjusted to exclude oil consumed by petroleum refineries, which was calculated separately as described in a following section. Sulfur contents for residual oil were based on the average sulfur content of residual oil consumed by industrial sources in the NEDS point source file. If NEDS data were not available or found to be unrealistic, sulfur contents were assumed to be equal to regional average values for Number 6 oil reported in DOE report Heating Oils, 1980 (DOE/BETC/PPS-80/4). Sulfur contents of distillate oil were computed as weighted averages based on the volumes of Number 1, 2 and 4 oil delivered to industrial users in each state as reported in DOE report (DOE/EIA-0113(79) and national averages of sulfur contents for each grade of oil as reported in Heating Oils, 1980.

Gas: State level industrial natural gas use (defined to include gas consumed by gas production plants and pipelines) was reported for 1979 in DOE report National Gas Production and Consumption DOE/EIA-0131(79). It was assumed that these data were representative of 1980, since 1980 data were not available. Reported national natural gas use for 1980 indicates little change from 1979. Industrial natural gas use was adjusted to exclude natural gas consumed by petroleum refineries, calculated separately as described in the petroleum refinery section. Gas reported in the industrial category was assumed to be consumed in boilers, with AP-42 Supplement 13 boiler emission factors used. Gas consumed by gas production plants and pipelines was assumed to be in reciprocating engines or turbines. Emission factors from AP-42 were weighted on a national basis according to the quantity of gas consumed by industrial reciprocating engines and gas turbines as reported in the NEDS point source file. These national average emission factors were applied for all states for gas consumed by gas processing plants and pipelines.

Other Fuels: Other fuels that may be consumed by industrial sources, such as wood, bagasse, LPG and others were assumed to contribute negligible amounts of SO_2 and NO_x emissions and were ignored in this analysis.

2.2.3 INDUSTRIAL PROCESSES

Industrial processes were divided into three categories. For the first category, emission estimates were derived for each process group, using methodology described below, which relies on published data to estimate production rates and AP-42 emission factors. For the second category, emission estimates were obtained directly from the December 1981 NEDS point source file. For category 1 processes, it was assumed that the emission estimates derived from published data were more representative of true

1980 emissions estimates than data in NEDS. For category 2 processes, NEDS data were compared with EPA national emissions estimates reported in National Air Pollutant Emissions Estimates, 1940-1980 (EPA-450/4-82-001) and found to be in reasonable agreement. The data reported in this publication are assumed to represent EPA's best estimates of national emissions. In other cases (natural gas plant flares and sulfite pulp mills), emissions were taken directly from NEDS because no other reliable procedure for estimating emissions at the State level could be developed and implemented within the time frame available for this project. Since the adequacy of the data for these two source categories cannot be confirmed by an independent national emissions estimate, their validity is questionable. The data from NEDS were used, due to the lack of other alternative data. The industrial processes included in category 2 are listed below:

- Non-ferrous smelters
- Kraft pulp mills
- Sulfite pulp mills
- Iron and steel (sintering machines only)
- Natural gas plant flares

Within the non-ferrous smelter category, a closer examination of the NEDS data for specific plants revealed that emissions for some plants appear to be very questionable in NEDS despite overall agreement at the national level with emissions reported in EPA-450/4-82-001. Revised estimates of emissions for a small number of facilities with significant SO_2 emissions were obtained from the appropriate State agency or EPA Regional Offices in these cases.

The processes included in categories 1 and 2 account for the great majority of SO_2 and NO_x emissions from industrial processes. Category 3 represents all other processes. For this category an aggregated estimate to cover emissions from these other processes was calculated from NEDS data. The NEDS emissions of sources in categories 1 and 2 was subtracted from the total NEDS industrial process emissions for each State. The difference represents the emissions from other sources.

Emissions for category 1 processes were estimated as described below:

2.2.4 PETROLEUM REFINING

Included in petroleum refining are these processes:

- Process heaters: Oil and gas consumed by petroleum refineries in 1980 is reported in the DOE Annual Petroleum Statement. These fuels are assumed to all be consumed in process heaters, and AP-42 Supplement 13 emission factors for oil and gas fired boilers were used to calculate emissions. Sulfur contents of oil and refinery process gas were derived from NEDS average values for each state. If NEDS data were unavailable or appeared to be erroneous, national average default values of 1% sulfur for residual oil, 0.3% sulfur for distillate oil and 0.25% sulfur for refinery gas were used.

- Catalyst regenerators for catalytic cracking units: Production rates were estimated based on facility capacities reported in the March 24, 1980 Oil & Gas Journal. AP-42 emission factors, assuming no control, were applied to calculate emissions.

- Sulfur recovery: Production rates for recovered sulfur are reported in the U.S. Bureau of Mines Minerals Yearbook. National recovered sulfur production by petroleum refineries was allocated to states according to capacity of sulfur recovery operations at petroleum refineries as obtained from the Directory of Chemical Producers (SRI International, Menlo Park, CA). Emission factors were derived from AP-42 average values for 2, 3, and 4 stage Claus recovery plants, weighted according to the production reported for each state for each stage plant as given in the NEDS point source file.

2.2.5 CEMENT PLANTS

1980 cement production data by state were obtained from the U.S. Bureau of Mines report Cement in 1980, (Mineral Industry Surveys). Production for combined groups of states (allocated among states) was based on individual cement plant capacities as reported in Keystone Coal Industry Manual (McGraw-Hill, Inc.). Fuels consumed by cement plants are reported at the national level in the above Bureau of Mines report. The Keystone manual reports some fuel consumption data for individual plants, but data are not complete. The national coal use by cement plants was allocated to states, using a combination of coal use data from the Keystone manual, NEDS point source data, and a national average factor of 0.213 tons of coal consumed per ton of cement produced, derived from Bureau of Mines reported national data. Oil and gas consumed by cement plants do not contribute significantly to SO_2 emissions and were ignored. SO_2 emissions are calculated in two parts. First, SO_2 due to sulfur contained in the cement raw materials was calculated based on the AP-42 emission factor. SO_2 from coal combustion in cement kilns was calculated using an emission factor of 26 times the sulfur content, the standard emission factor used in NEDS. This assumes a net release of 65% of the sulfur contained in the coal. The actual emissions of SO_2 may be reduced further in facilities that employ fabric filter controls because of reactions between SO_2 and the alkaline dust collected on the filters. No attempt was made to consider this additional control, and as a result cement SO_2 emissions may be somewhat overestimated. Approximately 30% of the cement kiln records in NEDS report fabric filters as particulate control devices. The sulfur contents of coal used were the same values as derived for industrial coal consumption. NO_x emissions were calculated using the AP-42 emission factor of 2.6 lb/ton of cement produced.

2.2.6 COKE PLANTS

Emissions from coke plants associated with iron and steel mills were calculated from coal consumption data for coke plants reported in the DOE report Coke and Coal Chemicals in 1980 (DOE/EIA-0120/80). Total SO_2 emissions are associated with both underfiring of coke oven batteries and combustion of coke oven gas in other combustion units within iron and steel mills. From AP-42, approximately 33% of sulfur in coal charged to coke ovens is transferred to coke oven gas. Quantities of coal charged and average sulfur contents for individual states were obtained from the DOE report cited above. No controls on SO_2 were assumed. For NOx the industrial natural gas boiler emission factor from AP-42, Suplement 13 was assumed to apply to coke oven gas combustion in other combustion equipment. The total coke oven gas reported in the DOE report in the category "other use by producers" was assumed to represent coke gas combustion in boilers or other combustion equipment in steel mills.

2.2.7 SULFURIC ACID, AMMONIA, AND NITRIC ACID

1980 production data for these chemicals was obtained from Current Industrial Reports, produced by the U.S. Department of Commerce. Where production is reported only for groups of states, the group production was allocated to individual states based on plant capacity data obtained from the Directory of Chemical Producers . For ammonia, an average emission factor of 5.7 lb NOx/ton was obtained from AP-42. For sulfuric acid plants and nitric acid plants, AP-42 emission factors were used along with NSPS emission limitations to estimate emissions in each state. Plants subject to NSPS limitations were identified through a comparison of plant capacity data given in current and previous editions of the Directory of Chemical Producers, together with changes in production data for different years given in Current Industrial Reports.

2.2.8 SULFUR RECOVERY AT NATURAL GAS PROCESSING PLANTS

Production rates for recovered sulfur were obtained from Minerals Yearbook. Sulfur recovered by petroleum refineries was excluded from the state production totals. Emission factors, derived from AP-42 and NEDS data in the same manner as described previously for petroleum refineries, were used to compute estimated emissions.

2.2.9 OTHER SOURCE CATEGORIES

Emission estimates for all other categories of sources were obtained from State emission summary reports based on NEDS files. A preliminary update of the NEDS area source file was completed to provide data representative of 1980. The procedures for calculation of NEDS area source data are described in detail in the AEROS Users Manual (EPA-450/2-76-029) and in background documentation for a number of NEDS computer programs. A brief summary of the procedure used in NEDS for each major area source category is given below:

Residential Combustion: County fuel use estimates are computed based on the estimated number of dwelling units using each type of fuel and the number of heating degree-days. Housing data are obtained from the Census of Housing, available from the Bureau of Census, and degree-days are obtained from the National Oceanographic and Atmospheric Administration. County fuel totals are normalized to agree with state fuel use totals given in U.S. Dept. of Energy reports. Average emission factors from AP-42 are applied to calculate emissions.

Commercial Combustion: State fuel use totals are obtained from Department of Energy Reports. In NEDS, these state fuel use totals are divided into various commercial and institutional sub-categories and apportioned to counties. Average emission factors from AP-42 are used to calculate emissions.

Highway Vehicles: County level estimates of VMT are based on measured VMT data obtained from state Highway Departments or are calculated based on the number of vehicles registered in each county. Total VMT are allocated to vehicle classes based on the estimated amount of fuel consumed by each class of vehicle and average miles per gallon factors for each vehicle class. The estimated quantity of fuel consumed by each class of vehicle is based on state total gasoline and diesel fuel consumed by highway vehicles as reported in Highway Statistics, published by the Federal Highway Administration. These state totals are allocated to counties based on vehicle registrations by class in each county. Emission factors are computed for each vehicle class for each county by a NEDS computer program which is a simplified version of EPA's MOBILE2 model. Vehicle mix by model year is based on vehicle registration data for each county. Average annual state-wide ambient temperatures are used for each county in a state. National average values for the percentages of vehicles operated in hot and cold start conditions are used for all counties. To compute emissions, the VMT in each county are divided into two road speed categories representing rural and urban roads. For all urban roads, average speed is assumed to be 19.6 miles per hour and for all rural roads average speed is assumed to be 45 miles per hour. The VMT in each county are divided into rural and urban fractions based on the urban/rural split of available measured VMT or on the urban/rural population percentages for each county. Given these assumptions and input data, emission factors representative of each vehicle class and road speed category in each county can be computed. Emission factors take into consideration whether the county is in a low altitute area, high altitude area, or in California. The calculation procedure does not consider any of the MOBILE2 special correction factors that may be applied to account for air conditioning operation, trailer towing, or other factors. Also, the calculation procedure does not take into account areas where vehicle inspection and maintenance programs may be in effect.

Other Area Source Categories: Other area source categories defined in NEDS include off-highway motor vehicles (aircraft, railroads, vessels and other off-highway users of gasoline and diesel fuel), solid waste combustion, forest wildfires and forest managed burning, agricultural burning, and structural fires. Information on source extent is available from published references for most of these source categories. For solid waste combustion and structural fires, source extent is estimated based on population. Average emission factors derived from AP-42 are used to calculate emissions.

APPENDIX 3

APPENDIX 3

3. METHODOLOGY FOR CALCULATION OF UNCERTAINTY IN EMISSION ESTIMATES

Appendix 3 documents the procedures used by Canada and the United States to estimate the uncertainty of estimated emissions. The emission estimates were derived using procedures that are somewhat different for each country. For the U.S., the emission estimates for most source categories were computed from average emission factors and source activity levels available on a state-by-state basis. The calculation of probable errors was therefore designed to consider the probable error in each of these components and how they affect the overall error in calculated emissions.

For Canada, the emissions estimates for major source categories were compiled largely from estimated emissions for specific facilities. The error analysis performed by Canada thus emphasized an assessment of the various factors that influence the emissions for specific facilities. Emission totals for each major facility were then summed into source category totals for each province or source region.

For both countries, the state or provincial source category totals were accumulated in a similar manner to estimate national error levels. The following sections present a detailed discussion of the methodology used by each country.

3.1 ERROR METHODOLOGY FOR SO_2 AND NO_x INVENTORIES: CANADA

3.1.1 SO_2 ERROR ANALYSIS

This section deals with the precision of the 1980 sulfur dioxide emissions inventory on a nation-wide, provincial and source region basis. It should be pointed out however, that the reported precision values are not actually "true" precision, but rather the best estimate of precision that could be obtained.

The overall precision of the 1980 SO_2 emission inventory was established by considering the 14 major sectors which contribute approximately 97% to the total SO_2 emissions. Within these sectors, the emissions from 32 individual contributors (plants) account for 67% of the total SO_2 emissions and were treated on a plant-by-plant basis. Error estimates on the emission sources, other than those developed on a plant basis, were estimated on a sectorial basis. The assumed error was applied to the provincial emission totals for these sectors.

There were no "short-cut" methods available for determining the errors. The first step in the procedure was to review the methodologies in order to determine the sources of information. In addition, the review allowed a check for the following random errors:

1) Missing operating or technical data;
2) Erroneous technical data;
3) Inaccurate or outdated data;
4) Errors in calculation; and
5) Errors in emission estimates.

Spot checks and systematic reviews of emissions versus production and/or previous emission rates were also made to detect such errors. This procedure allowed the control of bias errors and blunders only, but did not influence the precision of the inventory.

Errors that affect inventories and which are not within the control of inventory groups are the determining factors in establishing the confidence that can be associated with an inventory. The following analysis is therefore limited to systematic errors. The sources of these errors are the parameters on which the sulfur dioxide emissions data are based and are as follows:

1) Production or consumption figures;
2) Generalized or outdated emission factors;
3) Results from stack sampling;
4) Variations due to maximum continuous rates;
5) Modifications to control equipment prior to stack sampling;
6) Variation of feed and or fuel;
7) Changes due to abnormal operation;
8) Sampling and analysis of inputs and outputs;
9) Control efficiencies for specific equipment; and
10) Fugitive emissions.

This list was prepared based on information taken from a publication (1) and from a review of the methodologies used to compile the inventory. A precision was then determined for each parameter by applying an engineering analysis based on published studies (2,3), previous experience, or engineering estimates. A breakdown of the overall precision for each point source and major sectors is given in Tables 3.1 and 3.2, respectively.

The determining factor in establishing the overall precision of an inventory is the engineering analysis of the errors on the above listed parameters which are used to develop the SO_2 emission estimate. This analysis can be very extensive and include a statistical analysis of all the data or it can be obtained by examining the methods used for compiling the data and estimating the probable errors. The latter procedure was used in this case. The methodology used to develop a precision value for each of these parameters is examined below.

Precision of Production or Combustion Figures

The source of the throughput data was considered. Data supplied by plants whose production was closely monitored for production purposes were assigned a precision of ± 5 percent, otherwise ± 10 percent was assumed. Throughput data on fuel consumption were rarely obtained directly from a plant. Such data were generally obtained from Statistics Canada and precisions of ± 20 to ± 50 percent were used. A major fuel with a small percentage of unaccounted consumption would be assigned ± 20 percent while other fuels such as LPG's whose consumption for specific purposes is often unaccounted were assigned ± 50 percent. General production data obtained from Statistics Canada or Energy, Mines and Resources Canada were assumed to be precise within ± 10 to ± 30 percent depending on the number and the size of the plants.

Precision of Emission Factors

Emission factors are arrived at by numerous methods. Many factors are compiled from source test data or material balances. These factors should be very precise for the specific process and for the operating conditions during the test at the specific plant. All plants producing a given product do not operate under identical conditions although the processes are the same; hence, a precision of ± 15 to ± 30 percent was assumed. For fuel combustion emission factors, where combustion units and burners are of many different designs, precisions of ± 25 and ± 55 percent were used.

Precision of Stack Sampling Data

Although stack sampling results are regarded to be the most accurate source of emission data, errors are introduced in measuring the sampling volume, off-gas flowrate, maintaining isokinetics, etc. According to the literature (3) specific to stack sampling procedures, the precision of such tests is ± 10 percent. For continuous monitors the precision was assumed to be ± 6 percent, since the analysis is performed at the site within seconds of the sampling time.

Precision due to Rate of Production

The production rate of any process can vary continually unless it is always operating at maximum production. The oxidation of sulfur is dependent on numerous process parameters such as temperature, excess oxygen, etc. which can vary with the rate of production. On the other hand, most processes are operated with constant process conditions irregardless of the throughput rate; consequently, a precision of ± 5 percent was attached to this parameter. A precision of ± 10 percent was assumed only if the plant operations were at a start-up stage.

Precision due to Control Equipment

Control equipment efficiency can vary over a wide range. Most equipment will be overhauled when the efficiency drops to a pre-set minimum, however, the normal operating efficiency could be several percentage points higher. Prior to any stack sampling tests, the control equipment will generally be overhauled to operate at its maximum efficiency. To account for this practice, a precision of ± 10 percent was included.

Precision due to the Variation of Feed or Fuel

This parameter is highly dependent on the type of operation and the source of the raw material. The sulfur content of ore bodies and crude fuel can vary considerably and no source sampling test will compensate for this parameter, since tests are run on a relatively short cycle. The precision attached to this parameter was ± 10 percent and was based solely on the limited knowledge of feed sources.

Precision due to Abnormal Operations

Process upsets are very common for some operations and can drastically affect the oxidation of sulfur; moreover, such upsets can reduce control equipment efficiencies considerably. Precisions between ± 5 and ± 25 percent were assigned to the various operations based on the potential for upsets. This parameter was included since source sampling tests will generally be terminated prior to any abnormal conditions.

Precision of Sampling and Analytical Methods

This parameter is very important when the emissions are based on mass balances. Process input and output materials are generally not homogenous and the basic composition can vary as discussed above, under variation of feed or fuel. The analytical procedures are generally very accurate. However, grab sampling which is often used, can lead to gross errors. As a result, precisions of ± 10 or ± 15 percent were assumed based on a knowledge of the process input and output materials.

Precision of Specific Control Equipment

This parameter should be accounted for if source sampling tests were carried out on control equipment inlets or if uncontrolled emission factors were used. In such cases, published control efficiences for different types of controls are used to arrive at controlled emission values. These efficiences are not necessarily applicable to the control devices in question and therefore a precision of ± 10 percent is attached to this uncertainty.

Precision of Fugitive Emissions

For emissions established by source sampling, any emissions that are emitted prior to reaching the main off-gas outlet or the sampling point are not accounted for in the inventory. Most processes have numerous areas where gases can escape and; therefore, a precision of ± 5 percent has been assumed irregardless of the type of process.

3.1.2 STATISTICAL ANALYSIS

As described in the previous section, the random errors for major point sources and sectors were determined by assigning relative uncertainties to the computed emissions. The precisions of national, provincial and source region emissions were then calculated using the relationship: (4)

$$\theta = \left[\sum_{K=1}^{n} \left(\frac{Q_K}{Q} \right)^2 \delta_K \right]^{1/2}$$

where, Q_K = quantity of SO_2 emissions produced by source sub-class K (Tonnes/year)
100 δ_K = percentage error associated with Q_K
100 θ = percentage error associated with Q
Q = sum of the emissions from the source subclasses.

To facilitate these calculations, a hierarchical emission data tree was prepared for each province and source region. An example of the emission data tree for the national emissions is given in Figure 3.1. The trees were set-up so that precisions for specific sub-categories of emissions were also computed.

The precisions of the provincial and source region inventories for sulfur oxides are summarized in Tables 3.3 and 3.4, respectively.

TABLE 3.1

Summary of Assigned Errors on SO_2 Emissions for Specific Point Sources

COMPANY	LOCATION	PERCENT ERROR ON INDIVIDUAL PARAMETERS*										ERROR ON PLANT EMISSIONS
		1	2	3	4	5	6	7	8	9	10	
INCO	Sudbury, Ont.	5							10			15
Noranda	Noranda, Que.	5							10			15
Hudson Bay	Flin Flon, Man.	5							10			15
INCO	Thompson, Man.	5							10			15
Ont. Hydro	Courtright, Ont.	5					5		15			25
Ont. Hydro	Walpole, Ont.	5					5		15			25
Algoma	Wawa, Ont.	5					5		10			20
Falconbridge	Sudbury, Ont.	5							10			15
Gaspé	Murcochville, Que.	5							10			15
Suncor	Fort McMurray, Alta.	5		10	5			25			5	50
Ont. Hydro	Mississauga, Ont.	5					5		15			25
INCO	Sudbury, Ont.	5					5		10			20
N.B.P.C.	Coleson Cove, N.B.	5					5		15			25
Aquitaine	Rocky Mt., Alta.	2					5		10			17
Syncrude	Fort McMurray, Alta.	5		10	10			25			5	55
N.B.P.C.	Minto, N.B.	5					5		15			25
N.S. Power	Point Tupper, N.S.	5					5		15			25
N.S. Power	Lingan, N.S.	5					5		15			25
Cominco	Trail, B.C.	5		10	5	10		5	10		5	50
N.S. Power	Trenton, N.S.	5					5		15			25
N.S. Power	Windmill Rd., Tuft's Cove	5					5		15			25
Chevron	Fox Creek, Alta.	2					5		10			17
Westcoast	Fort Nelson, B.C.	2					5		10			17
Nfld. Power	Holyrood, Nfld.	10	35									45
N.B.P.C.	Dalhousie, N.B.	5					5		15			25
West Coast	Taylor, B.C.	2					5		10			17
N.S. Power	Glace Bay, N.S.	5					5		15			25
Ont. Hydro	Unwin Ave., Toronto	5					5		15			25
N.B.P.C.	Courtney Bay, N.B.	5					5		15			25
B.M.&S.	Bathurst, N.B.	5		10	5	10		5			5	40
Ont. Hydro	Thunder Bay, Ont.	5					5		15			25
Alcan	Kitimat, B.C.	5		10	5			5			5	30

* Numbers correspond to parameter numbers in text, Appendix 3.1.1

TABLE 3.2

Summary of Assigned Errors on SO_2 Emissions for Individual Sectors

Sector	Percent Error on Individual Parameters										
	1	2	3	4	5	6	7	8	9	10	Overall
Industrial F.C.	25	28									53
Natural Gas Processing	10		10	5	10	5	15			5	60
Petroleum Refining	20	35									55
Power Generation	20	40									60
Residential F.C.	28	26									54
Commercial F.C.	25	25									50
Sulphite Pulping	15	30									45
Sulphate Pulping	15	30									45
Aluminum Prod.	10		10	5		5				5	35
Pyrrhotite Roasting	5		10			10	10			5	40

* Numbers correspond to parameter numbers in text, Appendix 3.1.1

TABLE 3.3

Provincial SO_2 Precision Estimates

Province	Emissions (Tonnes/Year)	Precision (± %)
Newfoundland	60 925	25.7
Prince Edward Island	5 794	44.1
Nova Scotia	218 781	14.5
New Brunswick	215 428	14.4
Quebec	1 157 916	14.5
Ontario	1 830 625	9.3
Manitoba	489 918	10.3
Saskatchewan	57 796	42.3
Alberta	539 357	29.3
British Columbia	192 868	17.3

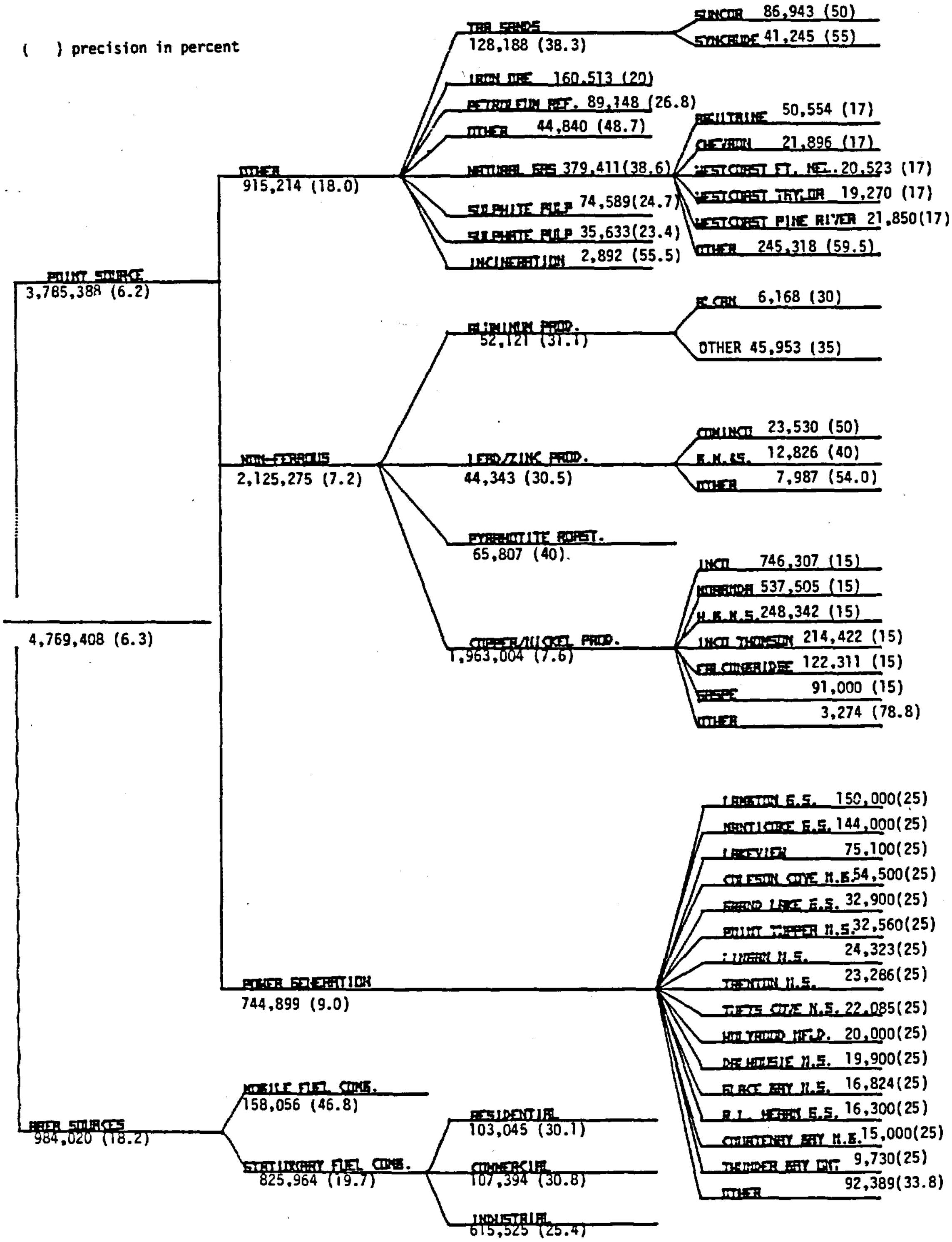
TABLE 3.4

Source Region SO_2 Precision Estimates

Source Region No.	Emissions (Tonnes/Year)	Precision (± %)
10	464 115	10.6
11	25 803	46.8
12	24 842	26.8
13	180 180	18.0
14	939 838	14.1
15	650 760	17.9
16	35 005	37.6
17	467 234	33.7
18	559 762	14.4
19	130 920	17.8
20	215 428	14.4
21	224 575	14.5
22	60 925	25.7
23	597 153	27.5
24	192 868	17.3

FIGURE 3.1

SO$_2$ SENSITIVITY ANALYSIS



3.1.3 NO_x ERROR ANALYSIS

The precision of the 1980 nitrogen oxides emission inventory was determined using the same basic methodology as was used for the sulfur dioxide inventory. The reported precisions were again the best estimate of precision and not actually "true" precisions. Moreover, the uncertainties associated with the compilation of nitrogen oxide emissions are considerably greater than for sulfur dioxide, hence, it was much more difficult to assign best estimates of precision.

Error estimates on the emission sources were estimated on a sectorial basis except for the power generation sector, in which case the errors were assigned on a point source basis for the major plants. The assumed error was again applied to the provincial emission totals. An additional error of ± 10 percent was introduced to all area source sectors for precision computations on a source region basis when source region emissions were prorated from provincial emissions (i.e. for source regions within Quebec, Ontario and Manitoba).

The nitrogen oxide emissions inventory was found to have a relatively high uncertainty since the formation of these oxides is highly dependent upon the combustion temperature of different processes (5). This factor is reflected in several of the following parameters that have been identified as probable sources of systematic errors:

1) Production or consumption figures;
2) Generalized or outdated emission factors;
3) Results from stack sampling;
4) Variations due to maximum continuous production rates;
5) Changes due to abnormal operation;
6) Effect of combustion equipment maintenance;
7) Control efficiencies for specific equipment;
8) Variations due to combustion equipment designs;
9) Effect of ambient temperature; and
10) Uncertainty as to the form of the emitted oxide.

These parameters were obtained based on a review of the methodologies used to compile the inventory, and from the literature (1,5). A precision was determined for each parameter on a sectorial basis as in the precision analysis of sulfur dioxide emissions (Table 3.2). The methodology used to develop a precision value for each parameter is given below.

Precision of Production or Consumption Figures

The sources of base quantity data were considered for all sectors. The reasoning for selecting specific precisions are outlined in the SO_2 error analysis section. For forest fires and slash burning, sectors not considered under SO_2, a precision of ± 25 percent was assigned based on the estimate of the quantity of biomass burned per unit area which can vary considerably.

Precision of Emission Factors

Emission factors for nitrogen oxides are determined mainly from source sampling tests. The results apply directly to the source that is sampled however; sampling procedures are prone to errors and since no two processes operate under identical conditions, additional errors are introduced by averaging emission factors. For mobile sources, an additional error of ± 10 percent was introduced as a result of vehicle mix and vehicle degradation. Emissions from forest fires and slash burning are highly variable hence a precision of ± 50 percent was judged appropriate.

Precision of Stack Sampling Data

Only the emissions from power generating stations in Ontario were based on actual measured values. No information on the error of NO_x measurements was found, hence, the error was assumed to be similar to that for SO_2 source sampling, ± 10 percent.

Precision Due to Rate of Production

Fuel consumption rate generally varies with process production which often influences process temperatures. A precision of ± 10 percent was assumed if considerable production variations occurred, otherwise a precision of ± 5 percent was used.

Precision Due to Abnormal Operations

Process upsets that affect SO_2 emissions also affect NO_x emissions because process temperatures change. Precisions between ± 10 and ± 25 percent were assigned to the various operations based on the potential for upsets.

Precision Due to Maintenance of Combustion Equipment

Soot build-up on burners, boiler walls, and heat exchangers has an effect on combustion chamber temperatures. Mechanical wear on a number of burner parts changes fuel/air mixtures thereby affecting flame temperatures. The effect of such factors cannot be considered in any emission inventory because emission factors are generally developed from source tests on overhauled combustion equipment. A precision of ± 5 percent was estimated for sources adhering to rigid maintenance programs, otherwise precisions of ± 15 percent were used.

Precision Due to Control Equipment

Nitrogen oxides emissions are uncontrolled with the exception of the automotive sources which, since 1975, are equipped with catalytic converters. A precision of ± 5 percent was assigned since neither the variation in efficiencies nor the degradation factor of the converters is considered for emission inventory purposes.

Precision Due to Design of Combustion Equipment

Designs of combustion equipment are endless. Some equipment is designed to operate at higher combustion temperatures than others. No distinction is made as to the operating specifications or the application of any burner for the non-utility stationary fuel combustion sectors. Precisions between ± 10 to ± 20 percent were therefore assumed with regard to this parameter.

Precision Due to the Effect of Ambient Temperature

The formation of nitrogen oxides is highly temperature dependent. Literature reviews revealed that relatively small combustion air temperature variations do not affect combustion temperature. In addition, large industrial installations use pre-heated air as combustion air. A study (6) revealed however, that some variations in NO_x formations were observed with regard to mobile sources. A precision of ± 5 percent was therefore assumed for these sectors.

Precision Due to the Type of Oxide Emitted

For most sectors, the form of the nitrogen oxide emitted is not known. Studies at power generating stations indicate that NO is the principal compound emitted, hence, a precision of ± 5 percent was assumed. An error of about ± 50 percent is theoretically possible with regard to this observation for the other sectors, however, a precision of ± 20 percent was judged applicable for this parameter since an unknown ratio of NO_x compounds is generally emitted.

3.1.4 STATISTICAL ANALYSIS OF NO_x ERRORS

The precisions of the provincial, and source region inventories for nitrogen oxides are summarized in Tables 3.6 and 3.7, respectively. The overall national inventory was found to have a precision of ± 10.3 percent. The precisions assigned to the various sectors were used together with a weighted sensitivity analysis outlined in Section 3.1.3 to compute these overall precisions. The emission data tree for national emissions is shown in Figure 3.3.

TABLE 3.5

Summary of Assigned Errors on NO_x Emissions for Individual Sectors

Sector	Percent Error on Individual Parameters*										
	1	2	3	4	5	6	7	8	9	10	Overall
Power Generation											
Plant Basis-Nfld	10	15		10	10	5				5	55
N.S.	5	15		10	10	5				5	50
N.B.	5	15		10	10	5				5	50
Ont.	5		10	10	10	5				5	45
Other	20	15		10	10	5				5	65
Non-Utility Fuel Comb.											
Residential	28	15				15		20		20	98
Commercial	25	15				10		15		20	85
Industrial-											
Gas Plants	15	15		10	20	5		10		20	95
Refineries	5	15		5	20	5		10		20	80
Other	25	15		10	20	10		10		20	110
Fuelwood	50	30								20	100
Mobile Fuel Comb.											
Gas Vehicles	5	25					5		5	5	45
Diesel Vehicles	10	25							5	5	45
Railways	5	25							5	5	40
Other	50	25							5	5	85
Miscellaneous											
Forest Fires	25	50								20	95
Slash Burning	25	50								20	145
Industrial Sources											
Aluminum	10	15		5	20					20	70
Tar Sands	5	15		5	25					20	70
Petroleum Refining	20	15		5	20					20	80
Sulfate Pulping	15	15		5	20					20	75
Nitric Acid	10	15		5	20					20	70
Incineration	30	15		10	25					20	100
Other	10	15		5	20					20	70

* Numbers correspond to parameter numbers in text, Appendix 3.1.3

TABLE 3.6

Provincial NO_x Precision Estimates

Province	Emissions (Tonnes/Year)	Precision (+ %)
Newfoundland	31 148	28.8
Prince Edward Island	6 849	24.9
Nova Scotia	88 129	18.0
New Brunswick	59 247	21.6
Quebec	331 358	25.9
Ontario	536 469	21.7
Manitoba	78 157	22.2
Saskatchewan	148 264	25.1
Alberta	353 463	28.6
British Columbia	198 968	22.9

TABLE 3.7

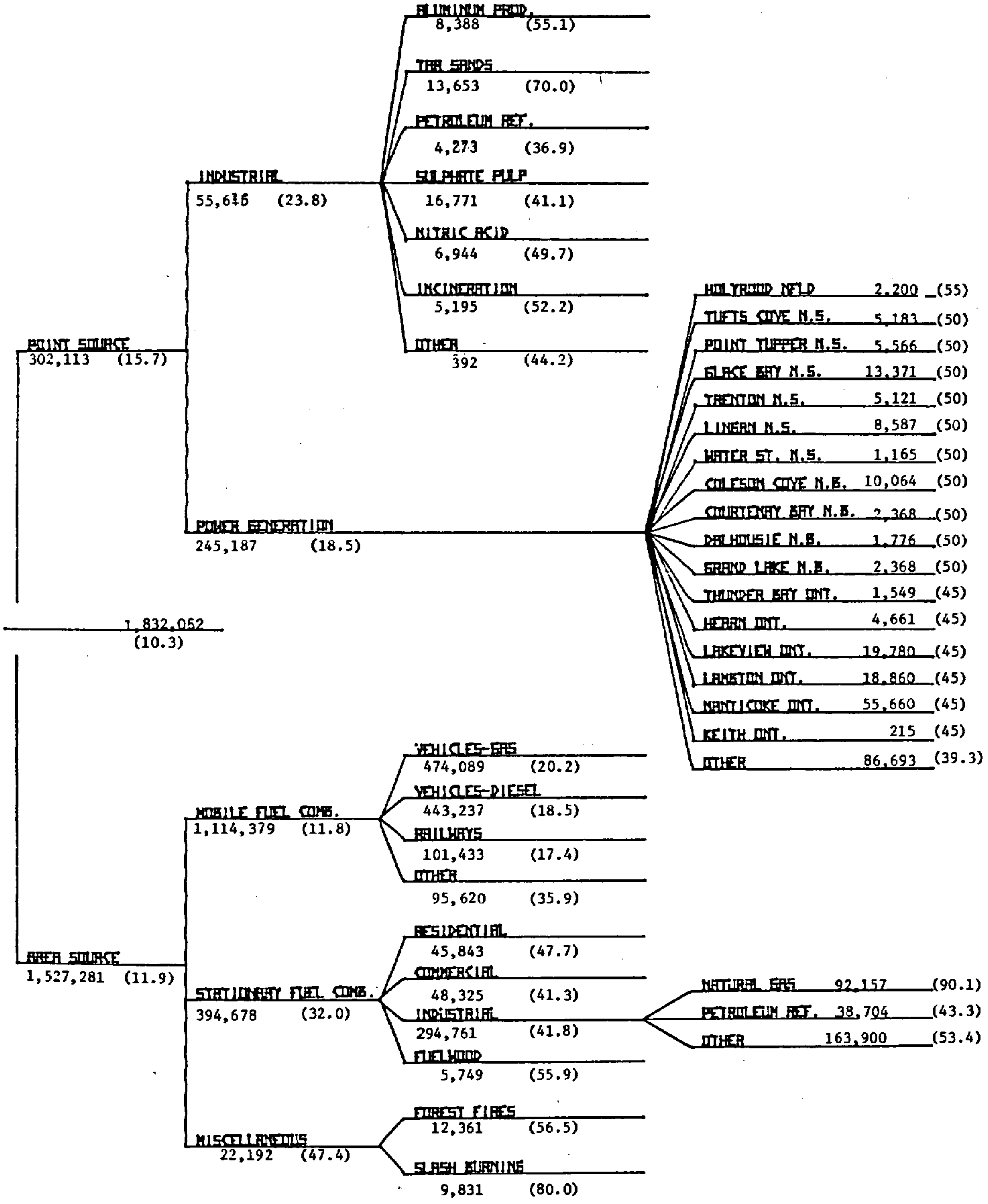
Source Region NO_x Precision Estimates

Source Region No.	Emissions (Tonnes/Year)	Precision (+ %)
10	5 658	26.9
11	72 499	26.9
12	18 476	28.2
13	18 534	29.4
14	10 041	33.9
15	417 566	24.5
16	71 852	30.4
17	295 139	30.6
18	12 939	32.1
19	23 280	37.1
20	59 247	21.6
21	94 978	17.8
22	31 148	28.8
23	501 727	25.1
24	198 968	22.9

FIGURE 3.2

NOx SENSITIVITY ANALYSIS

( ) precision in percent



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3.2 ESTIMATION OF PROBABLE ERROR IN EMISSIONS DATA FOR THE UNITED STATES

Errors in the data included in an emission inventory may occur for a variety of reasons. Normally, "true" values of emissions for a specific geographic area are unknown. "Estimated" values of emissions may be obtained through a variety of techniques. These techniques may incorporate biases (inaccuracies) into the "estimated" emissions because the techniques employed depend upon data which are biased. For instance, an emission factor may not be representative of the population of sources to which it is applied. Similarly, engineering assumptions about process operating characteristics and rates may not be representative of a particular population of sources. Since, "true" emissions values cannot be obtained except through extremely detailed and costly source emission measurements which are generally impractical or are themselves subject to error, a comparison between "true" and "estimated" emissions values by standard statistical techniques to determine a true error is impossible.

Errors in the data also result from imprecision (sampling or random error) in the data itself. Imprecision is caused by the inherent variation, or scatter, of the data in the data base. Measurement techniques for parameters such as fuel sulfur contents or for source emission sampling have limited ability to reproduce exact measurements. Likewise, emission factors result in imprecise emission estimates as they are merely averages based on a number of scattered observations. Generally, imprecision of an inventory can be reduced by increasing the number of observations of parameters used to develop emission estimates and by employing measurement techniques which are inherently more precise.

Finally, errors in emission inventory data may result from mistakes. Mistakes may result from arithmetic errors, reporting of data in incorrect units, keypunching errors and other errors in coding and copying of emission inventory input data. Mistakes occur at random in the data base, but can be effectively reduced through an effective quality assurance program that provides for cross-checking of calculations and recorded data.

For the sulfur and nitrogen oxides emission estimates included in this report, an attempt was made to estimate the "probable error" in the data. The "probable error" represents an estimate of the error in the data resulting from biases and imprecision. It does not address errors caused by any mistakes in the data, but rather, any major mistakes that occurred in the preparation of the data have been corrected through quality assurance procedures. Any remaining mistakes hopefully have a small impact on the overall accuracy of the data. To assess the probable error in the estimated emissions, a technique was developed which is based on assessing the probable errors in each of the component variables used to calculate the estimated emissions for each category of sources. Based on these estimates, a statistical procedure can be employed to calculate the probable error in the calculated emission values for each source category and in the summed emission totals for each state and the nation. The probable errors reported are therefore estimates which are themselves subject to error. However, because of the impracticality of approaches for determining "true" errors in estimated emissions, the probable errors reported represent a reasonable first step in the estimation of emission inventory errors. Through refinement of the techniques used to estimate the errors in individual emission data components, the methodology could be improved to provide more accurate estimates of probable errors.

In general, the probable error of a quantity Z_t calculated from independently observed quantities Z; with probable errors r_j may be computed as:

$$\text{Probable Error } Z_t = \left[\sum_{i=1}^{m} \left(\frac{dZ_t}{dZ_i} \right)^2 r_i^2 \right]^{1/2}$$

For example, if $Z = Z_1 Z_2$, the probable error in Z is

$$\text{Probable Error } Z_t = (Z_1{}^2 r_2{}^2 + Z_2{}^2 r_1{}^2)^{1/2} \tag{1}$$

If $Z = Z_1 Z_2 Z_3$, the probable error in Z is

$$\text{Probable Error } Z_t = [(Z_2 Z_3)^2 r_1{}^2 + (Z_1 Z_3)^2 r_2{}^2 + (Z_1 Z_2)^2 r_3{}^2]^{1/2} \tag{2}$$

These equations can be applied to calculate probable errors for SO_2 and NO_x emission estimates. The probable error in NO_x emissions can be calculated using equation (1) where

Z_1 = Source production rate
Z_2 = NO_x emission factor
r_1 = Probable error in source production rate
r_2 = Probable error in NO_x emission factor

The probable error in SO_2 emissions can be calculated using equation (2) where

Z_1 = Source production rate
Z_2 = SO_2 emission factor
Z_3 = Sulfur content
r_1 = Probable error in source production rate
r_2 = Probable error in SO_2 emission factor
r_3 = Probable error in sulfur content

The probable error in SO_2 emission calculations where a sulfur content is not involved can be computed by assuming that Z_3 = 1.0 and r_3 = 0. This is equivalent to reducing equation (2) to the form of equation (1).

Once the probable errors in the emissions from each source category have been calculated, the probable errors in the State and national emissions totals accumulated as sums of the source category emissions estimates may be calculated. The probable error of a State emissions total is

$$\text{Probable Error}_{\text{State}} = \left[\sum_{j=1}^{h} (\text{Probable Error Category } j)^2 \right]^{1/2}$$

The probable error of the national emissions estimate is

$$\text{Probable Error}_{\text{Nation}} = \left[\sum_{i=1}^{m} (\text{Probable Error State } i)^2 \right]^{1/2}$$

Examples of these calculations are given below. The calculated values of probable errors in 1980 SO_2 and NO_x emission estimates for each state and the nation are given in Table 3.8. Table 3.9 shows the detailed results for one state with values of the input variables, estimated probable errors in these quantities, and calculated probable errors in the emissions for individual source categories shown. Similar tables for other states have not been included in this report but are available from Chuck Mann at RTP, NC (919/541-5694 or FTS 629-5694).

It should be emphasized that the estimated inventory errors for a given region are not intrinsic or unchangeable. They can, in fact, be significantly reduced at any time by improving the method of estimating emissions (i.e. measurements or mass-balance versus emission factors).

TABLE 3.8
Probable Errors in Estimated Emissions

State	Total SO_2 (10^3 MT/YR)	Probable Error (+%)	Total NO_x (10^3 MT/YR)	Probable Error (+%)
Alabama	707.0	8.3	408.6	8.2
Alaska	15.3	18.0	52.2	10.3
Arizona	817.2	19.0	233.8	7.5
Arkansas	92.0	14.2	197.2	9.5
California	405.6	14.1	1 111.4	9.1
Colorado	122.2	20.9	250.8	7.1
Connecticut	65.3	10.3	121.6	10.2
Delaware	99.0	8.7	47.1	22.9
District of Columbia	13.4	14.0	19.9	15.2
Florida	993.2	18.4	588.0	12.3
Georgia	752.3	9.1	448.3	8.8
Hawaii	53.0	8.7	41.0	11.1
Idaho	42.5	16.7	73.8	18.4
Illinois	1 336.1	7.5	912.0	11.1
Indiana	1 818.7	7.2	701.3	14.1
Iowa	299.3	10.3	290.9	13.9
Kansas	196.6	11.0	396.6	7.6
Kentucky	994.6	8.3	482.0	12.2
Louisiana	276.2	10.2	842.2	8.6
Maine	86.0	10.5	53.9	9.6
Maryland	306.6	7.9	225.1	8.3
Massachusetts	312.5	6.6	230.0	10.7
Michigan	822.6	11.7	625.9	8.7
Minnesota	238.8	11.3	338.8	12.1
Mississippi	261.2	9.2	258.8	8.2
Missouri	1 179.6	8.5	514.9	13.9
Montana	153.1	24.2	114.0	12.6
Nebraska	68.0	16.8	176.5	12.9
Nevada	225.3	50.8	75.5	16.9
New Hampshire	84.1	8.5	50.6	13.9
New Jersey	253.3	10.8	368.3	10.6
New Mexico	257.2	34.5	262.8	8.9
New York	864.0	5.9	616.5	8.4
North Carolina	546.8	10.2	486.5	8.6
North Dakota	126.1	21.1	113.1	18.3
Ohio	2 398.4	11.1	1 038.4	11.3
Oklahoma	109.3	12.9	477.0	9.3
Oregon	54.4	14.2	174.2	10.9
Pennsylvania	1 812.4	7.7	941.2	9.2
Rhode Island	13.8	11.1	33.1	11.9
South Carolina	301.7	8.4	236.1	15.8
South Dakota	35.5	21.3	80.8	15.2
Tennessee	976.5	8.0	469.2	8.1
Texas	1 182.0	16.0	2 307.7	8.8
Utah	80.5	13.9	130.8	7.2
Vermont	6.1	15.1	22.4	12.7
Virginia	327.1	6.8	367.1	10.6
Washington	246.8	18.7	262.1	11.2
West Virginia	989.4	8.6	410.3	12.0
Wisconsin	544.1	9.6	381.4	9.4
Wyoming	168.7	15.1	231.4	9.4
National Total	24 131.5	2.3	19 293.1	2.0

TABLE 3.9

STATE: ALABAMA

SOURCE CATEGORY	PROD RATE	SO_2 EMISSION FACTOR	% SULFUR	NO_x EMISSION FACTOR	SO_2 EMISSIONS	NO_x EMISSIONS
UTILITY COAL	19593	.018	1.59	8.8E-03	560.75 TONS	172.42 TONS
Errors:	3%	8%	6%	15%	10.4%	15.3%
UTILITY DIST. OIL	3	.072	.36	.012	.08 TONS	.04 TONS
Errors:	25%	7%	20%	12%	32.8%	27.7%
UTILITY GAS	1.4	3E-04	1	.143	0 TONS	.2 TONS
Errors:	10%	50%	0%	35%	51%	36.4%
INDUSTRIAL COAL	1840	.0195	1.25	8.55E-03	44.85 TONS	15.73 TONS
Errors:	10%	8%	12%	13%	17.5%	16.4%
INDL RESID OIL	220	.0795	1.9	.0275	33.23 TONS	6.05 TONS
Errors:	18%	7%	5%	12%	19.9%	21.6%
INDL DIST OIL	79	.072	.22	.0162	1.25 TONS	1.28 TONS
Errors:	20%	7%	20%	12%	29.1%	23.3%
INDL BOILER GAS	145	3E-04	1	.07	.04 TONS	10.15 TONS
Errors:	3%	50%	0%	25%	50.1%	25.2%
INDL IC ENGINE GAS	34	3E-04	1	1.25	.01 TONS	42.5 TONS
Errors:	6%	50%	0%	12%	50.4%	13.4%
COMML BITM COAL	122	.0181	1.25	6E-03	2.76 TONS	.73 TONS
Errors:	50%	12%	16%	12%	53.9%	51.4%
COMML RESID OIL	.3	.0795	1.9	.0275	.05 TONS	.01 TONS
Errors:	25%	7%	10%	13%	27.8%	28.2%
COMML DIST. OIL	29	.072	.22	.01	.46 TONS	.29 TONS
Errors:	25%	7%	20%	13%	32.8%	28.2%
COMML GAS	36	3E-04	1	.05	.01 TONS	1.8 TONS
Errors:	7%	50%	0%	18%	50.5%	19.3%
RESIDTL BITM COAL	87	.0155	1.5	1.5E-03	2.02 TONS	.13 TONS
Errors:	30%	20%	20%	100%	41.2%	104.4%
RESIDTL DIST OIL	1.4	.072	.2	9E-03	.02 TONS	.01 TONS
Errors:	30%	7%	20%	7%	36.7%	30.8%
RESIDTL GAS	66	3E-04	1	.05	.02 TONS	3.3 TONS
Errors:	5%	50%	0%	6%	50.2%	7.8%
ALUMINUM SMELTERS	231	6.9E-03	1	0	1.59 TONS	0 TONS
Errors:	10%	75%	0%	0%	75.7%	0%
PROCESS HTRS-NAT GAS	7	3E-04	1	.07	0 TONS	.49 TONS
Errors:	10%	50%	0%	25%	51%	26.9%
PROCESS HTRS-REF GAS	11	.415	.18	.07	.82 TONS	.77 TONS
Errors:	15%	15%	25%	25%	32.8%	29.2%
PROCESS HTRS-R. OIL	2	.0795	1	.0275	.16 TONS	.06 TONS
Errors:	15%	7%	14%	12%	21.7%	19.2%
PROCESS HTRS-D. OIL	2	.0216	1	.01	.04 TONS	.02 TONS
Errors:	25%	7%	0%	12%	26%	27.7%
SULFUR RECOVERY	376	.08	1	0	30.08 TONS	0 TONS
Errors:	15%	12%	0%	0%	19.2%	0%
COKE OVENS	4849	6.47E-03	.8	7.5E-04	25.1 TONS	3.64 TONS
Errors:	10%	50%	15%	40%	53.2%	41.2%

TABLE 3.9 (continued)

STATE: ALABAMA

SOURCE CATEGORY	PROD RATE	SO_2 EMISSION FACTOR	% SULFUR	NO_x EMISSION FACTOR	SO_2 EMISSIONS	NO_x EMISSIONS
IRON SINTERING	1	4.2	1	0	4.2 TONS	0 TONS
Errors:	0%	50%	0%	0%	50%	0%
CEMENT-MINERAL	2520	5.1E-03	1	1.3E-03	12.85 TONS	3.28 TONS
Errors:	10%	100%	0%	100%	100.5%	100.5%
CEMENT-COAL	535	.013	1.26	0	8.76 TONS	0 TONS
Errors:	20%	50%	18%	0%	56.8%	0%
SULFURIC ACID	195	7.75E-03	1	0	1.51 TONS	0 TONS
Errors:	15%	40%	0%	0%	42.7%	0%
AMMONIA	226	0	1	2.85E-03	0 TONS	.64 TONS
Errors:	15%	0%	0%	30%	0%	33.5%
NITRIC ACID	121	0	1	.0215	0 TONS	2.6 TONs
Errors:	15%	0%	0%	40%	0%	42.7%
KRAFT PULP	4842	2.66E-03	1	8.3E-04	12.88 TONS	4.02 TONS
Errors:	10%	45%	0%	50%	46.1%	51%
SULFITE PULP	1	0	1	0	0 TONS	0 TONS
Errors:	0%	100%	0%	0%	0%	0%
NAT GAS FLARES	1	8.6	1	0	8.6 TONS	0 TONS
Errors:	0%	100%	0%	0%	100%	0%
MISC PROCESSES	1	12.4	1	4.7	12.4 TONS	4.7 TONS
Errors:	0%	100%	0%	100%	100%	100%
SOLID WASTE	1	.4	1	2.3	.4 TONS	2.3 TONS
Errors:	0%	75%	0%	75%	75%	75%
HIGHWAY VEHICLES	29027	3.26E-04	1	5.01E-03	9.46 TONS	145.43 TONS
Errors:	3%	50%	0%	15%	50.1%	15.3%
AIRCRAFT	1	.295	1	2.448	.3 TONS	2.45 TONS
Errors:	0%	50%	0%	50%	50%	50%
RAILROADS	1	.366	1	2.389	.37 TONS	2.39 TONS
Errors:	0%	55%	0%	30%	55%	30%
VESSELS	1	3.274	1	3.014	3.27 TONS	3.01 TONS
Errors:	0%	60%	0%	60%	60%	60%
OFF-HIWAY GAS	1	.06	1	1.45	.06 TONS	1.45 TONS
Errors:	0%	50%	0%	50%	50%	50%
OFF-HIWAY DIESEL	1	.756	1	9.167	.76 TONS	9.17 TONS
Errors:	0%	50%	0%	40%	50%	40%
MISC BURNING	1	.3	1	8.5	.3 TONS	8.5 TONS
Errors:	0%	100%	0%	100%	100%	100%

TOTAL SO_2 EMISSIONS: 779.47 TONS
TOTAL ERROR: 8.3%

TOTAL NO_x EMISSIONS: 449.55 TONS
TOTAL ERROR: 8.2%

Sample Calculations of Probable Errors

I. Calculation of Probable Error in Industrial Coal SO_2 emissions for Alabama

From Table 3.9:

Production Rate = 1840×10^3 tons
SO_2 Emission Factor = 39 lb/ton ÷ = 0.0195 tons/ton
% Sulfur = 1.25%

Probable Error in Production Rate =
$\pm 10\% = 1840 \times 0.1 = 184 \times 10^3$

Probable Error in Emission Factor =
$\pm 8\% = 0.0195 \times 0.08 = 1.56 \times 10^{-3}$

Probable Error in Sulfur Content =
$\pm 12\% = 1.25 \times 0.12 = 0.15$

SO_2 Emissions =
$(1840 \times 10^3)(0.0195)(1.25) = 44.85 \times 10^3$ tons

Probable Error in SO_2

$$= [((0.0195)(1.25)(184 \times 10^3))^2 + ((1840 \times 10^3)(1.25)(1.56 \times 10^{-3}))^2 + ((1840 \times 10^3)(0.0195)(0.15))^2]^{\frac{1}{2}}$$

$$= [4485^2 + 3588^2 + 5382^2]^{\frac{1}{2}}$$

$$= [61,954,893]^{\frac{1}{2}}$$

= 7871 tons

$$\frac{7871}{44.85 \times 10^3} = 17.5\%$$

II. Calculation of Probable Error in Total SO_2 Emissions for Alabama

From Table 3.9:

Probable error in utility coal SO_2 =
$\pm 10.4\% = 560.75 \times 10^3$ tons $\times 0.104$
$= 58.32 \times 10^3$ tons

Probable error in utility dist. oil SO_2 =
$\pm 32.8\% = 0.08 \times 10^3$ tons $\times 0.328$
= 26 tons

As above for remaining source categories —

Probable Error $_{\text{ALL } SO_2}$ =

$[(58.32 \times 10^3)^2 + (26)^2$ ---etc. for all categories$]^{\frac{1}{2}} = 64.7 \times 10^3$ tons

$$\frac{64.7 \times 10^3}{779.47 \times 10^3} = 8.3\%$$

3.2.1 ESTIMATION OF PROBABLE ERRORS IN SOURCE PRODUCTION RATES AND SULFUR CONTENTS

Production Rates

Source category production rates at the state-level are derived from a number of literature references. Normally, these references do not include any quantitative statistical information about the accuracy of the data. In some instances, a measure of the sampling error or imprecision of the data is given. This information may be used to estimate one component of the total probable error. The quantification of bias in the data must be based on estimates, however.

To derive estimates of the total probable error in state level production rates, a variety of procedures were used. One procedure was to assume that a typical overall error in production rates was applicable to all state production totals. Such values were estimated using reasonable engineering judgement. A second procedure was to assume that national production totals were inherently accurate, or have a very small error, usually one percent or less. Given these national level errors, maximum values for state-level errors, such that the overall national error is not exceeded, can be computed based on a weighted sensitivity analysis of the data. Maximum state errors may be calculated as:

$$\text{State Error (\%)} = \text{National Error (\%)} \left(\frac{\text{National Production Rate}}{\text{State Production Rate}}\right)^{1/2}$$

This calculation yields a variable value for the state level error depending upon the ratio of national production rate to state production rate. The result is that for states where this ratio is small the calculated state error is also small. Where this ratio is large, the calculated state error becomes large. This calculation quantifies the observation that in states where the production rate is large, the production total is probably based on a relatively large number of observations and thus, is likely to have a relatively small error. In states where the production rate is low, the total production is probably based on a small number of observations and is thus more likely to have a larger error. This weighted sensitivity analysis procedure was used to calculate probable errors in production rates for electric utility and industrial combustion source categories. For these categories, it is possible to make reasonable estimates of national errors in production rates, allowing maximum state level errors to be calculated. In cases where the national-to-state production ratio is extremely large, the calculated state level errors were arbitrarily assigned some reasonable maximum value rather than the calculated value, which could exceed ± 100%. For most industrial process source categories and residential and commercial combustion categories, state level errors were assumed to be the same for all states. This procedure appears to be justifiable because each of these individual source categories usually only contributes a small proportion of the total emissions. Performing the more detailed weighted sensitivity analysis calculations for all these additional source categories would have been much more time-consuming. The calculated errors in state total emissions generally would not be significantly different, regardless of which procedure was used.

For highway vehicles it was possible to calculate probable errors in state VMT totals by comparing calculated VMT from NEDS with reported state VMT totals in Highway Statistics. VMT estimates in NEDS are calculated based on number of registered vehicles and average miles travelled per vehicle per year. Highway Statistics VMT are based on reports by state agencies. Comparing the two values for VMT revealed that in most instances, the two values were in agreement within ± 3%. Therefore in these cases, it was assumed that the probable error in VMT was ± 3%. When the NEDS value differed from the Highway Statistics value by more than ± 3%, the percentage difference calculated was used as the probable error in state VMT.

For miscellaneous industrial processes, solid waste, forest fires, etc., emission estimates were taken directly from NEDS reports. Each of these categories contains a number of sub-categories. All of these categories usually make a minor contribution to total SO_2 and NO_x emissions. Estimation of errors in production rates for all of these categories and sub-categories would be a time-consuming, extremely speculative procedure. Therefore, the normal calculation procedure was bypassed. Instead, estimates of the overall error in SO_2 and NO_x emissions (usually from ± 50% to ± 100%) for these categories were made. Input data values used to calculate probable errors for these source categories were assigned, such that the estimated errors in emissions would be computed directly as the probable errors. Because of the relatively small contribution to total emissions from these miscellaneous source categories, the probable error in state total emissions is generally insensitive to whatever the error in the emissions from miscellaneous sources may be.

Sulfur Contents

Available data on fuel sulfur contents may be subject both to imprecision and biases. Estimates of the imprecision of fuel sulfur content measurements were obtained from Source Inventory and Emission Factor Analysis (EPA-450/3-75-082). This report was produced in 1974 as part of an EPA contract effort to develop a procedure for estimating the precision of NEDS data.

For fuels consumed by electric utilities, reported data for individual facilities are available from U.S. Department of Energy reports. It was assumed that since electric utilities are generally large consumers of fuel that may require analyses of fuels consumed to satisfy air pollution control requirements or to meet fuel purchase contract specifications, that the probable error in sulfur contents were due largely to sampling errors. The contribution to probable error due to biases in the data was assumed to be negligible.

For fuels consumed by industrial, residential and commercial sectors, the probable error was assumed to incorporate some bias in addition to sampling error. Derived state averages for fuel sulfur contents are based on limited samples of fuels that may not be representative of all fuel consumed in the state. In addition, procedures used to weight the reported sample values to determine a statewide average may bias the results. Possible procedures for quantifying these biases are extremely speculative. For this project, the biases were approximately accounted for by assuming that the probable errors in sulfur content values for industrial fuels were equal to 1.5 times the sampling error, and for residential and commercial fuels were equal to twice the sampling error. For process gas consumed by petroleum refineries no data were available for either sampling error or bias. Thus, estimates of the probable error were made by assuming a sampling error for refinery gas that is similar to the estimated errors for other fuels.

3.2.2 ESTIMATION OF PROBABLE ERRORS IN EMISSION FACTORS

Probable errors in emission factors were estimated by the Air Management Technology Branch, Monitoring and Data Analysis Division (MDAD), Office of Air Quality Planning and Standards (OAQPS) using background files available for selected SO_2 and NO_x emission factors taken from Compilation of Air Pollutant Emission Factors, EPA Publication AP-42.

In most cases where sufficient background test data was utilized to derive the factors, a systematic analysis was performed to determine probable error. This analysis defines error as a function of (1) the number of observations used to determine each factor, (2) the variability of those observations and (3) the number of sources to which each factor might typically be applied in a state-wide inventory. In cases where this analysis could not be rigorously applied, such as where a material balance was used or where the background data were simply unavailable, less rigorous procedures were applied based on engineering judgement.

In certain instances, the analyses yielded error values exceeding ± 100 percent, often because the underlying distributions for some factors were more likely log-normal rather than normal. In these cases, we somewhat arbitrarily limited the probable error to ± 100 percent. Of course, be cautioned that any error estimates are just that--estimates. Due to the lack of data, a strict derivation of absolute error bounds for each source is a theoretical and practical impossibility.

A mathematical description of the error in an emission factor may be represented as

$$Xn - Ec \leqslant Xk \leqslant Xn + Ec$$

where Xn is the AP-42 emission factor based on n observations

Xk is the true emission factor average for the k specific sources it represents

Ec is the confidence interval about Xn for a confidence level of c, and is a function of n, k, and c.

If the underlying emission factor population is normal, and if Xn and Xk are from the same population (both of these assumptions are questionable in some cases), Ec can be derived from a Student statistic for the difference between two sample means from the same underlying population:

$$Ec = (tc)\left[\frac{(K-1)Sk^2 + (n-1)Sn^2}{k+n-2}\right]^{1/2}\left[\frac{1}{k} + \frac{1}{n}\right]^{1/2} \qquad (1)$$

where Sk and Sn are the sample standard deviations of Xk and Xn and tc is the Student-t statistic for (k+n-2) degrees of freedom and confidence C. In the general case, k, n, Xn, tc, and Sn will be known, but Sk will be unknown. Sk can be approximated by observing that from equation (1), Sk is important only where $k \geqslant n$. In these instances, it may be assumed that Sk can be approximated by σx, where σx is the standard deviation of the entire emission factor population from which both Xn and Xk are derived. Given this, equation (2) below can be used to estimate an upper limit of σx from Sn. This estimate yields a slightly high estimate of Ec.

$$Sk = \sigma x = \left[\frac{(n-1)Sn^2}{X^2}\right]^{1/2} \qquad (2)$$

where X_2 is the chi-square statistic for (n-1) degrees of freedom and some desired confidence level.

To facilitate the use of this analysis, a normalized version of equation (1) has been solved via computer, for various values of k, n, Xk, and Sn. A normalized variation of equation (1) may be expressed as:

$$\begin{matrix}\text{Normalized}\\ \text{Error}\end{matrix} = \frac{Ec}{Xn} = tc\left[\frac{(k-1)Vk^2 + (n-1)Vn^2}{k+n-2}\right]^{1/2} \left[\frac{1}{k} + \frac{1}{n}\right]^{1/2} \qquad (3)$$

where Vk and Vn represent the coefficients of variation (the standard deviation divided by the mean) for k and n.

$$VK = \frac{Sk}{Xn} = \left[\frac{(n-1)Vn^2}{Xc^2}\right]^{1/2}$$

$$Vn = \frac{Sn}{Xn}$$

It should be noted that the normalized precision errors have been determined at the 90 percent confidence level which is believed to be adequate for this application. If more confidence is desired, the resulting normalized errors would be greater. Similarly, if a lower degree of confidence is acceptable, the normalized errors would be smaller.

APPENDIX 4

APPENDIX 4

4. 1978 SO_2 EMISSIONS INVENTORY

4.1 UNITED STATES

In addition to the 1980 emission inventory presented in section C of this report, an inventory of sulfur dioxide emissions for 1978 was produced. This inventory was required by Work Group 2: Atmospheric Modeling, for use in a model validation and comparison process. Many components of this inventory were produced in earlier phases of the Work Group efforts, with some refinement incorporated during Phase III. To meet the needs of Work Group 2, the 1978 inventory was disaggregated to a finer level of geographic detail than has been done for 1980 inventories. In addition, this 1978 inventory was required earlier in Phase III to meet the immediate needs of Work Group 2. As a result, though the 1978 SO_2 inventory represents the best information which could be provided in the time allowed, the estimates are cruder then those provided for in the 1980 SO_2 inventory. The methods used to produce the 1978 inventory were also slightly different.

The U.S. 1978 SO_2 emission inventory was assembled from several available sources. State level utility sector emissions and point source emissions for the largest 200 power plants were produced using the same methodology as was used for 1980 emissions. This methodology is described in Appendix 2 of this report.

State level 1978 SO_2 emission estimates for all other sectors were developed for 32 eastern states by the Mitre Corporation under contract to EPA (1,2). These non-utility emission estimates were calculated for 1980 but were considered to be the best available estimates for 1978 non-utility emissions and were utilized as such.

The disaggregation of the emissions for the eastern U.S. was prepared by the Modeling Sub-group of Work Group 2 after consultation with Work Group 3B. Emissions for the largest 200 utility emitters were available in 1978 and were located by the latitude and longitude. The remaining utility emissions for the states were distributed to point sources by scaling an existing 1979 point source inventory. The scaling factor was determined by subtracting the emissions of the 200 power plants from both inventories and comparing the remaining emissions from the two inventories for each state. The 1979 utility emission estimates and plant locations were supplied by the Ontario Ministry of the Environment (3). These emissions were calculated in a manner similar to that described in Appendix 2.

The non-utility emissions were disaggregated within each state by scaling by state the non-utility sources in the MAP3S SO_2 inventory prepared by Brookhaven National Laboratory (BNL) to the totals given by the Mitre Corporation. In the BNL MAP3S inventory (4), point sources are located by their latitude and longitude. Area emission sources are presented as county totals located at the area centroid of the county.

The western U.S. emission distribution was provided by Work Group 3B. The large point sources, except utilities, were taken from the 1978 NEDS files (5) and were identified by latitude and longitude. The utilities emissions were available for the largest emitters and state totals as described. All other emissions were extracted from NEDS and presented by Air Quality Control Regions (AQCR).

After the 1978 inventory was delivered to Work Group 2, a moderately minor error was discovered in the methodology used to calculate SO_2 emissions for the 32 eastern states. Oil sulfur contents used for residential and commercial sector calculations were incorrect. The effect of this error was to overstate residential emissions by approximately a factor of two and to overstate commercial SO_2 emissions by a smaller percentage. Although these errors are large with respect to the affected sector totals, state and national SO_2 emission totals are not substantially affected.

U.S. 1978 SO_2 emissions data provided to Work Group 2 are summarized by state in Table 4.1.

REFERENCES

1. The Mitre Corporation, Letter Report W54-1066 prepared by the U.S. Environmental Protection Agency, Office of Research and Development, April 24, 1981.

2. Background Information for the Unified Sulfur Dioxide Emissions Inventory, The Mitre Corporation, Working Paper 81W638, Prepared for Environment Canada, November 9, 1981.

3. U.S. Power Plant Emissions in 1979, Air Resources Branch, Ontario Ministry of the Environment, Internal Draft Report, 1982.

4. Benkowitz, Caramen, Compiling a Multistate Emissions Inventory, Brookhaven National Laboratory Report, BNL-26843, 1980.

5. 1978 National Emissions Data System, National Emissions Report, U.S. Environmental Protection Agency Report No. ___.

TABLE 4.1
1978 SO_2 Emissions For The U.S. Summarized By State
(emission given as 10^6 kg SO_2/year)

Region Number	State	State Emission		
		Utility	Non-Utility	Total
50	Ohio	2 203.8	575.1	2 778.9
51	Illinois	1 190.0	367.4	1 557.4
52	Pennsylvania	1 316.6	656.6	1 973.4
53	Indiana	1 225.2	492.9	1 718.1
54	Kentucky	1 085.5	113.1	1 198.8
55	Michigan	727.4	332.3	1 059.7
56	Tennessee	937.2	138.2	1 075.4
57	Missouri	918.3	189.5	1 107.8
58	West Virginia	813.7	132.9	946.6
59	New York	471.6	535.8	1 007.4
60	Alabama	495.4	159.8	655.2
61	Wisconsin	410.3	154.9	565.2
	Iowa	241.0	101.4	342.4
62	Minnesota	176.6	103.2	279.8
63	Virginia	202.0	148.3	350.3
	North Carolina	359.9	165.7	525.6
64	Florida	539.6	188.6	728.2
65	Georgia	552.4	101.1	653.5
	South Carolina	178.5	87.1	265.6
66	Maryland	199.9	96.9	296.8
	Delaware	50.4	34.7	85.1
	New Jersey	104.7	228.4	333.1
	District of Columbia	9.4	36.1	45.5
67	Arkansas	53.4	47.5	100.9
	Louisana	57.8	213.6	271.4
	Mississippi	187.3	58.0	245.3
68	Massachusetts	234.6	183.4	418.0
	Connecticut	23.7	106.0	129.7
	Rhode Island	3.1	24.4	27.5
69	Maine	7.8	74.5	82.3
70	Vermont	0.3	13.2	13.5
	New Hampshire	47.4	26.0	73.4
71	Nebraska			60.2
	North Dakota	N/A	N/A	103.5
	South Dakota			45.0
	Montana			195.0
	Wyoming			177.6
72	Oklahoma			89.3
	Kansas	N/A	N/A	238.9
	Colorado			119.0
	New Mexico			470.9
	Texas			780.0
73	Washington			371.2
	Idaho	N/A	N/A	49.4
	Oregon			49.7
74	California			587.2
	Nevada	N/A	N/A	326.0
	Utah			205.4
	Arizona			1101.8
	Continential U.S. Subtotal			25 881.

4.2 CANADA

The Phase III Canadian SO_2 emission inventory, representative of 1978, was prepared by Environment Canada. The emission data were a mixture of 1976 and 1978 data with the most significant point sources, specifically thermal power plants and non-ferrous smelters, updated to their 1978 levels.

The 1976 data were taken from the National Emissions Inventory System (NEIS) and can be found in summary form in the report "A Nationwide Inventory of Emissions of Air Contaminants (1976)", EPS-3-AP-80-1, Air Pollution Control Directorate, 1981. The data for 1978 were either obtained from provincial agencies or from Environment Canada's internal files (unpublished information).

The emission data were provided to Work Group 2 by latitude-longitude for large point sources and on a 127 x 127 km grid spacing for area and small point sources. The emissions on a 127 x 127 km grid basis were derived from provincial estimates and prorated to each grid by means of census data obtained from Statistics Canada. For example, emissions for residential fuel combustion were first estimated provincially for each fuel type consumed in that sector, using the same methodology as was used for the 1980 inventory as described in Appendix 2. The provincial emission totals were subsequently apportioned to each grid in each province by taking the ratio of the number of dwellings in each grid that consumed a specific fuel over the total number of dwellings in that province that consumed the same fuel and multiplying by the provincial emission total from residential heating for that fuel type. The data were developed on this basis to provide Work Group 2 with the spatial resolution required for their modeling runs.

For brevity, the 1978 Canadian SO_2 emissions inventory is summarized in Table 4.2 by Canadian source regions used by Work Group 2 for the development of transfer matrices.

TABLE 4.2

1978 Canadian SO_2 Emissions
Summarized by Province and Modelling Source Regions
(emissions given as kilotonnes SO_2/year)

Region Number	Province(s) and Subregion	Region Emission Total	Provincial Emissions Total
10	Manitoba - Northern	473.5	
11	Manitoba - Southern	28.5	502.0
12	Ontario - Northwestern	17.9	
13	Ontario - Northwestern & Algoma	183.9	
14	Ontario - Sudbury	689.1	
15	Ontario - Southwestern & Toronto	667.6	
16	Ontario - Southeastern	51.5	1 610.0
17	Quebec - Montreal & St. Lawrence Valley	454.6	
18	Quebec - Northern	539.6	
19	Quebec - Gaspe Bay	79.3	1 073.5
20	New Brunswick	191.5	191.5
21	Prince Edward Island Nova Scotia	169.9	8.7 161.2
22	Newfoundland - with Labrador	59.5	59.5
23	Saskatchewan Alberta	560.9	41.5 519.4
24	British Columbia with Yukon/N.W.T.	247.7	244.6 3.1
	CANADIAN SUBTOTAL		4 415.0

APPENDIX 5

APPENDIX 5

5. CONTROL TECHNOLOGIES FOR SO_2

5.1 SULFURIC ACID PLANTS

Sulfuric acid is produced by burning sulfur or sulfur-bearing materials to form SO_2, which is converted to acid in an acid plant. Based upon the use of metallurgical acid plants for acid production from pyrite roasters and smelting operations, the contact acid plant has become the method of choice for control of sulfur dioxide from smelting operations. Metallurgical acid plants are classified as cold gas systems, as distinct from those burning elemental sulfur. This distinction is quite important as the reason behind it affects the economics and hence the applicability of this control technique. It arises because the cold gas process requires extensive gas pretreatment involving dust removal, cooling, and scrubbing for further removal of particulate matter and heavy metals, mist, and moisture required to protect the catalyst and maintain the water balance. Because of this treatment, the gas is at a low temperature when it enters the acid plant while that in a sulfur burning plant is hot. A number of processes, varying stages of development and use, are included in Table 5.1.

The conventional acid plant has been considered to be the single contact, single absorbtion (SCSA) type with multiple passes of the flue gas through the converter and cooling between each catalyst stage. The converter unit consists of three, four, or five fixed beds of catalyst with interstage cooling to maintain the optimum gas reaction temperature-conversion profile. Plants built before 1960 generally had only three conversion stages and operated with conversion efficiencies of about 95 to 96 percent. Plants built since 1960 have four or more converter stages and overall conversion efficiencies between 96 and 98 percent. The single contact plant requires approximately 3.25 to 4.0 percent SO_2 by volume in the incoming stream for autothermal operation, with 4.0 percent generally taken as the lowest practical operating limit. Lower concentrations require the use of natural gas (or other external heat source) which greatly increases the operating cost. The optimum upper limit is approximately 7.0 to 8.0 percent SO_2 by volume. Vendors generally will not guarantee performance to achieve less than 2000 ppm SO_2 content in the tail gas.

When gas streams contain less than 8 percent SO_2, the size of the equipment required to produce a given quantity of acid is relatively greater; when the streams contain less than 3.5 percent SO_2, auxiliary sulfur burning or make-up heat capacity is usually required. The capital and operating costs for a cold gas plant are therefore much higher than those for a corresponding sulfur burning acid plant.

An improved contact acid plant, called the double contact double absorption process (DCDA), has been available since about 1972. In this process, the main gas stream is passed through an intermediate absorption tower where the major portion of the SO_2 is removed after two or three catalyst passes. The gas is then returned to the converter for a final one or two stages of conversion. The double contact process requires a minimum SO_2 concentration of from 4.0 to 4.5 percent by volume with 4.5 percent preferred as the practical operating lower limit (to differentiate from the theoretical). Until recently the optimum (maximum) inlet concentration has been about 9.0 percent. The DCDA plant is capable of efficiencies of 99.7 to 99.8 percent, producing a tail gas containing less than 500 ppm, i.e., generally 100 to 300 ppm. The DCDA plant is generally used in place of an SCSA system to provide the emissions control. However, FGD systems have been used on SCSA tail gases, by the U.S. on sulfur burning plants and by Japan on metallurgical acid plants, to achieve equivalent control.

Acid mist is also emitted from sulfuric acid plants. The quantity of acid mist formed depends on the strength of acid produced, the type of sulfur feed-stock, and the absorption efficiency.

Sulfur dioxide emissions may exceed the normal emission rate during start-up (1 to 2 days) or abnormal (1/2 to a few hours) operations. The frequency and duration of the abnormal emissions depend on the plant design, type of control systems, and the nature of the start-up or operational problem. A single contact plant is shown in Figure 5.1.

The amount of SO_2 emitted during start-up depends on the time needed to bring all of the converter stages to the proper operating temperatures. Time required to achieve a stable operation of the plant depends on the length of the shut-down and the condition of the catalyst bed. When a plant has been charged with new catalyst, a start-up will require 1 to 2 days of slowly increasing production rates until full production is reached. Plants with catalyst exposed to moisture can be in full production in 3 to 4 days. During start-up, the emissions may be five times the normal rate for the first few hours if the final stage is not at the proper temperature before SO_2 is introduced into the converter. If the proceding stages are sufficiently heated to obtain nearly full conversion at reduced rates, reaction heat then continues the heating process until ignition is obtained in the final bed.

Upon completion of the preheating sequence, sulfur or sulfur-containing feed-stock is burned at a low rate using excess air to produce a weak SO_2 stream, which is fed to the converter. Adjustments are made to stabilize all operations, bringing all temperatures to normal conditions and gradually increasing the feed rate and inlet SO_2 concentration as the temperature of the first bed decreases and that of the last bed increases to ignition. These adjustments must be carefully coordinated to prevent loss of stability and resultant excessive SO_2 emissions.

During routine operation, several types of abnormal conditions can cause excessive emissions. Elemental sulfur-burning plants have the fewest problems because they operate with a relatively constant concentration of SO_2 to the converter. Plants using metallurgical off-gases are more prone to operating problems, the most common of which are: sudden change in concentration of SO_2 to the (acid plant) converter; oxygen starvation; equipment failure or power failure. Emissions during these conditions usually range from 50 to 100 percent higher than normal levels. Usually the operations are stabilized within 1/2 hour to a few hours.

The relation between the SO_2 strength of the inlet gas and the outlet gas, the sulfur conversion efficiency required and the SO_2 emission factor for acid plants is given in Figure 5.2. The capital cost of a double contact plant may be estimated from Figure 5.3. An estimate for the application of a single contact plant to a Canadian site is given in Table 5.2.

There are several FGS processes applied to tail gases from sulfur burning sulfuric acid plants in the U.S. These processes, which could be applied to all classes of contact acid plants when operated with a high efficiency Brink type mist eliminator in the final absorbing tower, provide simultaneous control of SO_2, SO_3, and acid mist. These are discussed in more detail in Appendix 5.2.

5.2 FLUE GAS SCRUBBING

The 0.5 to 1.5% SO_2 average concentration in reverberatory furnace off-gas is not sufficiently high for direct processing of the gas in a conventional sulfuric acid plant. For this reason, FGD systems have been incorporated at a few smelters under specific conditions. They may be classified as regenerative and nonregenerative; the former produces SO_2 as a more concentrated gas, and the latter generally converts it to a throwaway by-product.

The non-regenerative systems essentially neutralize the SO_2, converting it into a stable form which can be disposed of with minimal adverse effects on the environment. Regenerative systems absorb the SO_2 and then regenerate it as a more concentrated SO_2 stream which can then be used to make either liquid SO_2, sulfuric acid, or sulfur. In those cases where the sulfuric acid market is such that additional production is not saleable, the non-regenerative systems would seem to be the logical choice for controlling SO_2 from the smelter reverberatory furnace. In those cases where a by-product is to be produced, several possible concentration systems have been proven feasible at full-scale operations on reverberatory furnace off-gases. The costs, however, are substantial and each retrofit system must be considered on an individual basis.

As shown in Table 5.3, weak gas stream control technology is practised at some European and Japanese smelters. One North American smelter uses ammonia scrubbing, and a molybdenum roaster uses limestone scrubbing. The U.S. EPA has stated that lime, limestone, magnesium oxide and ammonia wet scrubbing systems have been adequately demonstrated to be technically feasible. However, because of lack of experience and the question of the economic feasibility of applying wet scrubbing systems to smelter gases in North America, the problem of weak SO_2 off-gas control remains the major issue of smelter pollution control. Flakt and Boliden are jointly developing a citrate system for smelter weak SO_2 which is at the pilot stage. The new Afton Mines smelter (Canada) employs a dual alkali system. Currently, the state-of-the-art is such that FGD by wet scrubbing can be accomplished but there are financial and technical risks in the selection, design and application of such systems owing to lack of extensive experience on various types of concentrates. The estimated capital and operating costs for four systems are compared in Figures 5.4 and 5.5, for a one percent SO_2 off-gas.

5.2.1 LIME-BASED FLUE GAS DESULFURIZATION SYSTEM

The schematics presented in Figures 5.6 - 5.8 show a generalized scrubbing system, reagent makeup and storage systems, and options for handling the scrubber bleed stream, respectively. As shown in Figure 5.6, gases containing SO_2 discharged directly from the smelting processes, or that have passed through the precooler (or venturi when particulates are to be removed from the gas stream), enter the absorption tower near the base. As the gases pass up through the tower, they are met countercurrently by the lime slurry absorbent. The lime slurry is initially prepared by reacting lime (CaO) with fresh water in a slaker, as shown in Figure 5.7. The calcium hydroxide product $Ca(OH_2)$ from the slaker, which contains about 40 percent solids, is diluted with recycled water to approximately 10 percent solids by weight. This dilute lime solution is pumped to the absorber recirculation tank, where it mixes with the recycled absorbent from the absorber. This mixture is then sprayed into a tray tower, where it contacts the SO_2 in the incoming gas stream. The reaction of the SO_2 with the slurry chemically removes most of the SO_2. If the absorber provides adequate contact time and area for the SO_2 and slurry, SO_2 removal efficiencies can be quite high. Sulfur dioxide removal efficiency of lime slurry FGD systems is approximately 90 percent. The gas stream leaving the absorber passes through a mist eliminator and is then mixed with hot air, through an induced-draft (I.D.) fan, before going to a new or existing stack. The mist eliminator captures entrained droplets and returns them to the circulating absorbent. The heated air mixes with the main gas stream to raise its temperature approximately 50°F so as to minimize dew point problems.

The liquid stream coming out of the absorber contains approximately 10 percent solids consisting primarily of calcium sulfite/bisulfite and calcium sulfate. Some unreacted lime is also present. Still able to remove SO_2, this liquid stream enters a recirculation tank, where it is mixed with the fresh makeup lime solution and then pumped back through the absorber.

To minimize buildup of calcium sulfite ($CaSO_3$), calcium sulfate ($CaSO_4$), and impurities in the absorption system, a bleed or purge stream is taken from the recirculation tank. As shown in Figure 5.8, this bleed stream can be handled in several ways, depending on whether the purged compounds are desired in a sludge form or solid form. About 7 to 8 percent of the liquid stream from the absorber recirculation tank is bled off. The overflow, a liquid with less than 1 percent solids, is sent to a holding tank for recycled water use. When the oxidation process is used, the underflow (approximately 20 percent solids) is pumped to multiple centrifuges to produce a gypsum cake with an 80 percent solids content. When a thickener/vacuum filter or thickener/ centrifuge is used without oxidation, the solid contents of the discharge is 60 percent. These solid wastes are trucked to a landfill or disposal pond.

In addition to that lost in the flue gas, water is lost in the sludge and gypsum systems, both as water of hydration and as free water. Water from the disposal pond is recirculated. Additional makeup water is added to the system as slaker feed water, pump seal water, and mist eliminator wash water. Water is also added through the gas cooler (when used). Capital and operating costs are given in Figures 5.9 and 5.10.

5.2.2. LIMESTONE-BASED FGD

The limestone-based FGD system is almost identical to the lime system. The only differences of any significance are in the preparation of the absorbent (described below and shown in Figure 5.11) and the SO_2 removal efficiency (85% compared with 90% for the lime system). Estimated capital and operating costs are presented in Figures 5.12 and 5.13.

Limestone is brought to the storage area at the plant by truck or by train. The limestone storage pile should be maintained at a level capable of supplying the plant for 30 to 90 days. From the storage pile the limestone is fed onto a conveyor that leads first to a 3-day silo and then to 24-hour silos. From there the limestone passes through a weigh feeder to a wet ball mill. The mill reduces the limestone to -200 to -300 mesh. The limestone slurry reaction requires the dissolution of $CaCO_3$, which is a slower reaction than the dissolution of CaO in the lime process. The rate of reaction is directly related to the particle surface area and therefore to the particle size. The limestone slurry (about 40 percent solids) is pumped first to a day tank and then to a dilution tank, where recycled water is added to dilute the slurry to approximately 10 percent solids. This makeup slurry is pumped to the absorber recirculation tank.

The limestone system, like the lime system, is a closed-loop process. Fresh water (or recycled water) is added to the system at the ball mill during grinding. It is also added as pump seal water and as mist eliminator wash water. The bleed stream is pumped from the absorber recirculation tank to the disposal area in a manner similar to that in the lime system, and a number of alternative treatment systems may be selected for cost estimating.

5.2.3. MAGNESIUM OXIDE SYSTEM

This scrubbing system (Figure 5.14) uses a slurry of magnesium oxide in water to absorb SO_2. The reaction product, magnesium sulfite, is then dried, and the magnesium oxide is regenerated and recirculated. This system recovers a high-strength sulfur dioxide suitable for conversion to liquid SO_2. Capital and operating cost estimates are provided in Figures 5.15 and 5.16.

The absorption portion of this process is very similar to the lime/limestone system. As the SO_2-laden gas stream ascends through the absorber trays, it is contacted counter-currently with the magnesium oxide (MgO) absorbent. The makeup MgO is prepared by mixing MgO with water to form a magnesium hydroxide solution (40 percent solids by weight) and then diluting it to a level of 10 percent solids. The SO_2 removal efficiency of this MgO solution is about 92 percent. The gas stream leaves the absorber, passes through a mist eliminator, is mixed with heated air to give a flue gas temperature of 80°C (177°F), and is then ducted to an I.D. fan for discharge to the atmosphere through a new or existing stack.

The liquid bleed stream out of the absorber recirculation tank contains mostly magnesium sulfite, some magnesium sulfate, some unreacted slurry, and other trace impurities. The magnesium sulfite formed in this regenerable system is dried and calcined to form magnesium oxide and a high-strength SO_2 gas for further processing. About 92 to 93 percent of the absorbent out of the absorber is recirculated. The remaining 7 or 8 percent is pumped to a liquid cyclone, the overflow is returned to the 10 percent dilution slurry tank, and the cyclone underflow is sent to a surge tank that feeds the multiple centrifuges. The centrifuges produce a wet cake, which is conveyed to a rotary dryer to remove the water. The liquid removed during centrifugation is returned to the 10 percent dilution makeup slurry tank. Dryer temperatures typically are in the range of 200° to 232°C (390° to 450°F). Products from the dryer are about 90 percent magnesium sulfite, and the remainder are basically magnesium sulfate and hydroxide.

The crystals out of the dryer are conveyed to a fluid-bed calciner where they break down to form MgO and SO_2 at a temperature of 600° to 800°C (1100° to 1475°F). The recovered MgO is sent to a storage silo. This regenerated MgO (with 1 to 3 percent $MgSO_4$), to which about 10 percent virgin MgO is added, supplies the slurry tank. This completes the MgO loop. A bleed stream for the removal of $MgSO_4$ from the 10 percent dilution tank is sent to a disposal pond or an emergency pond. The makeup solution from this dilution tank is pumped to the absorber recirculation tank.

The hot SO_2 gas released during calcining passes through a heat exchanger to preheat the combustion air for the calciner. This gas then goes to a cyclone, where MgO particles are collected and sent to the storage silo. The gas stream out of the cyclone, which contains approximately 10 percent SO_2, passes through a waste heat boiler and is suitable for recovery in a liquid SO_2 plant, a sulfuric acid plant, or an elemental sulfur plant.

5.2.4. COMINCO AMMONIA FGD

The Cominco process can achieve high efficiencies of SO_2 removal over a wide range of SO_2 concentrations, well within that encountered by smelting operations. Since the absorbent is a solution rather than a slurry, there are no scaling or plugging problems in the process. The system produces a concentrated SO_2 stream which can be used to produce sulfuric acid, elemental sulfur, or liquid SO_2. The main problem with this process is the loss of ammonia from the system. The ammonia volatility may limit the minimum level of SO_2 emission to 200 to 300 ppm for practical operations and also introduces costs that could produce an economic problem.

The schematic of the ammonia scrubbing process for controlling SO_2 from lead sintering plant gas at Trail, B.C. is given in Figure 5.17. A total of 300,000 scfm of flue gas from the lead sintering plant containing 0.75 percent SO_2 passes through a humidifying tower and a dust collector before entering the absorption plant. Then, the sulfur dioxide content is absorbed in aqueous ammonia, forming a solution that is essentially ammonium bisulfite.

The gas is treated in two parallel systems, each comprising a lead cooling tower, wood-supported and wood-packed, and three lead absorption towers, also wood-supported and wood-packed. Flow of water in the cooling tower, up to 1,600 gal/min, is countercurrent to the gas flow. The three absorption towers are constructed as a unit having two partitions with the required openings for gas dividing the structure into three towers. The flow of gas is concurrent with the solution in the first tower, countercurrent in the second tower, and concurrent in the third tower.

The circulating solution is pumped from the base of each absorption tower to a distributing spider at the top (flow being 1,200 to 1,500 gal/min in the first two towers and 600 to 800 gal/min in the third). Aqueous ammonia containing about 30 percent nitrogen is added to the circulation. Circulating solution temperature is controlled by passing it through water coolers (aluminum tubes and steel shell) immediately after the addition of ammonia, removing the heat of reaction. Temperature of the circulating solution is controlled at about 35°C in the first tower and about 2°C lower in each of the succeeding towers. Water from the tube coolers is used in the cooling towers before wasting to the sewer.

Solution is bled forward from one tower base to the next. The circulating solution is bled off the first tower to storage provided by two 60,000 gal lead lined wood stave tanks. The bled absorption solution from the zinc roaster ammonia absorption plant is also stored in these two tanks.

Mixed ammonium bisulfite solutions from the lead sintering and zinc roaster absorption plants, stored in the two bisulfite storage tanks, are filtered through Shriver presses using vinyon cloth and filter aid, and the filtrate is stored in a 200 000-gallon lead lined wood stave tank. The filter cake is returned to the smelter. The filtrate goes to a heat exchanger which is heated by hot ammonium sulfate solution. It is then further heated with steam in a stainless steel tubular heater, and mixed with sulfuric acid in a Pachuca-type acidifier. Two acidifiers are installed, one operating, one standby. The evolved sulfur dioxide gas and solution overflow into the eliminator, where the remainder of the gas is boiled off the ammonium sulfate solution as direct steam. Two eliminators are installed, one operating in series with each acidifier. These are constructed of steel, lined with Pyroflex and acidproof bricks, and packed with spiral rings.

From the eliminator, the ammonium sulfate solution, substantially free of sulfur dioxide, flows by gravity to a 200 000-gallon ammonium sulfate storage tank. This tank is all wood stave construction and lead lined. Coils are installed in the pump tanks, to preheat the bisulfite feed to the acidifier and in the heat exchanger. Aqueous ammonia is added to the ammonium sulfate in the pump tank to neutralize the free acid and produce a slightly ammoniacal solution to minimize corrosion of equipment. The ammonium sulfate solution from the storage tank (containing about 42 percent ammonium sulfate) is pumped to the fertilizer plant.

At Cominco, plant control is based on analysis of the inlet and tail gas and circulating solution from each absorption tower. Solutions are analyzed for pH. Aqueous ammonia is added to the solution to control the pH. At low pH, there is no SO_2 absorption and very high pH results in very high NH_3 losses. So the solution pH has to be maintained within a narrow range to give good SO_2 absorption and reasonably low NH_3 losses. This is achieved at Cominco by adding aqueous ammonia to each absorption tower and controlling the solution temperature to each absorption tower.

A serious problem that has been encountered with most of the ammonia scrubbing systems is the formation of an opaque fume in the exit gas stream. The fume is partly attributed to gas-phase reactions of ammonia, SO_2, and water forming ammonium sulfite, which, due to its small size, is not efficiently removed by a conventional mist eliminator. Wet electrostatic precipitators have been used at some installations to eliminate this problem. Cominco reported adequate control of the fume when operating with low liquid temperature to reduce the ammonia and SO_2 losses, and pretreating the gas before the absorbers. Pretreatment of the gas to decrease the particulate loading reduces the condensation nuclei on which ammonium sulfate could form. Cominco has conducted pilot tests and is currently preparing to install (by 1981) new equipment in their ammonia SO_2 control system to minimize or eliminate the stack opacity problem. The approach includes establishing critical pH and temperature ranges within the primary scrubber. Basic work on this technique has been done by Catalytic, Inc. (Philadelphia, Pa), which holds patents with emphasis on application to utilities.

5.2.5 SODIUM CITRATE FGD

The citrate FGD system, like the MgO system, is a regenerable type. No smelters use the citrate system on a full-scale basis, but Flakt at Boliden (Sweden), and the Bureau of Mines in the United States, have tested pilot versions on smelter gases. The following process description is based on information supplied by Flakt.

As in the other three FGD systems, the gas containing the SO_2 from the process unit, after cleaning in an existing ESP, is cooled and cleaned in scrubbers before going to the absorption tower. The SO_2 stream passes up through a packed absorption tower, where it is met by a countercurrent aqueous stream of sodium citrate. The citrate solution (citric acid and sodium citrate) is a buffering agent, which ties up hydrogen ions that form when SO_2 and water are brought together. The bonding of the hydrogen ions and the sodium radical that combines with the bisulfite ion maintain a solution pH of 6.5 to 7 and allows the dissociation of additional SO_2. Removal of SO_2 is enhanced by maintaining an optimum solution pH during the scrubbing process, which is accomplished by the use of sodium citrate, a good buffering agent. The absorption of SO_2 depends on the pH of the solutions; SO_2 removal is enhanced as the pH increases. The scrubbed gas stream from the top of the absorber passes through a mist eliminator and is then mixed with heated air to increase its temperature by 50°F before being ducted via an I.D. fan to a new or existing stack, in the same manner as the other scrubbing systems.

The SO_2-rich (in the form of sodium bisulfite) citrate solution leaving the absorber is pumped through a preheater to the top of the stripper (see Figure 5.18). Low-pressure steam is used in the stripper to remove the SO_2 from the solution. Thus, the sodium citrate solution is regenerated and pumped back to the regeneration unit and used again as the scrubbing medium. The SO_2 gas and some water leave the top of the stripper and pass through a cold-water condenser. The gas stream passes first through the mist eliminator at the top of the stripper for removal of entrained droplets, and then through a non-contact water condenser for cooling and condensing most of the water vapor from the gas stream. The condensed water, which contains a small amount of SO_2, is returned to the stripper. The stream that leaves the condenser is water vapor (2.3% by weight) and sulfur dioxide gas (97.7% by weight). This stream is sent to the liquid SO_2 plant.

Approximately 2 percent of the regenerated sodium citrate solution is purged from the system to prevent the buildup of sodium sulfate. Flakt has extensive experience operating a pilot scale system at the Boliden on smelter off-gas and is currently involved in a program to perform large scale tests on a power plant in the U.S. Estimates of the expected capital and operating costs for a full-scale system applied to a smelter are given in Figures 5.19 and 5.20.

5.2.6 DMA SCRUBBING

DMA (N,N-dimethylaniline, an organic liquid) scrubbing, developed by ASARCO for Tacoma, has been used for a number of years to collect and concentrate strong SO_2 from two U.S. smelters. The Cities Services Company operates two DMA systems to produce liquid SO_2 from a feed gas containing about 7.6% SO_2. ASARCO uses a DMA system to upgrade SO_2 and produce liquid SO_2 from off-gases containing as little as 4% SO_2. The DMA process is considered capable of operating with gas streams containing as low as 3% SO_2. It was tried out on reverberatory furnace gas at the Phelps-Dodge Ajo smelter (about 1.5% SO2) but did not operate properly and was abandoned. The process is illustrated in Figure 5.21.

As in most control processes, the gas stream must be free of dust and moisture for maximum operating efficiency. The sulfur dioxide gas stream is absorbed by the DMA in an absorption tower, then separated from the DMA with a steam strip, scrubbed with water to remove any residual DMA, dried, compressed, cooled, and liquified. DMA is recovered from the condensed stream and recycled. The advantage of this process is its efficiency over a large range of sulfur dioxide concentrations, from 3-10%. Operating costs increase with decreasing sulfur dioxide concentrations. Perhaps most importantly, the toxicity of the DMA itself makes containment quite critical.

5.2.7 ACID PLANT TAIL GAS FGD SYSTEMS (U.S.)

There are several FGS processes applied to tail gases from sulfur burning sulfuric acid plants in the U.S. These processes, which could be applied to all classes of contact acid plants when operated with a high efficiency Brink type mist eliminator in the final absorbing tower, provide simultaneous control of SO_2, SO_3, and acid mist.

Ammonia Scrubbing

Ammonia scrubbing can achieve SO_3 and acid mist removal comparable to that by the double absorption process. It often operates at 90 percent SO_2 removal efficiency. The process generates ammonium sulfate (liquor or crystals) as a by-product and may cause formation of a blue haze from emission of very fine particles of ammonium sulfate and sulfite.

Energy consumption is higher because of pressure drops in the absorber and the stripper, and the recirculation pumps. The energy penalty for a 907 MG (1000 ton/day) plant is estimated to be equivalent to 1.5 MW.

As of December 1977, there were 13 ammonia scrubbing systems operating in the U.S. Five installations met NSPS, four did not, and no emission data were available on the other four.

Limestone Scrubbing

Although limestone scrubbing provides adequate removal of the pollutants (SO_2, SO_3, and acid mist), it also generates a waste product, calcium sulfite/sulfate sludge, that needs proper handling and disposal. The sludge could be thickened, dewatered, stabilized, and landfilled; however, operators of limestone FGD systems on combustion sources currently tend to discharge unstabilized sludge to settling ponds.

The primary pieces of energy-consuming equipment are the booster blower (if required), recirculation pumps, ball mill (if any), thickener, filter, and conveyors and pumps. The overall energy penalty could be equivalent to 1.8 MW for a 907 Mg (1000 ton) per day plant.

Sodium Sulfite Scrubbing

The basic difference in the desulfurization of a flue gas and of an acid plant tail gas is in the adiabatic saturation temperature, which is much lower for the tail gas. The lower moisture content of the saturated tail gas (4 percent) further enhances the mass transfer by allowing the tail gas absorber to operate at about 32°C (90°F), and fewer mass transfer stages are required for the same SO_2 removal efficiency.

The environmental impact of sodium sulfate scrubbing is identical to that of the ammonia scrubbing except that it does not produce blue haze and the by-product is sodium sulfate instead of ammonium sulfate.

The energy penalty would be greater for the ammonia scrubbing process because the evaporators in the regeneration subsystem consume steam. The energy penalty for a 907 Mg (1000 ton) per day plant is about 2.5 MW.

Hydrogen Peroxide Scrubbing

One U.S. chemical company uses hydrogen peroxide (H_2O_2) scrubbing to control SO_2 emissions at two sulfuric acid plants. In this process, SO_2 in the gas stream is reacted with Tysule hydrogen peroxide to produce sulfuric acid. Dilute sulfuric acid (typically 50%) containing a small amount of H_2O_2 (0.1%) is circulated over polypropylene packing in an filer reinforced plastic (FRP) scrubbing tower. A rapid, high-yield reaction takes place in the recirculating acid medium, and the acid produced becomes part of the plant's product through blending with high-strength acid in either the drying or absorbing towers.

Since the reaction is $SO_2 + H_2O_2 = H_2SO_4$, the "make" acid from the Tysule scrubber is usable as "drip" acid in lieu of dilution water. There is no by-product and no purge stream to dispose of.

Process experience at the two plants has shown that the process is stable and easy to control. The effects of acid plant upsets are moderated by the scrubbing facility. Both plants have been in compliance with local standards covering emissions from existing sources. Although the process does not generate acid mist per se, mist entering the tail gas scrubber picks up the dilute recirculating acid which increases the size of the droplets and the visibility of the mist. Thus, a high-efficiency mist eliminator must be used for opacity control.

No published data are available regarding the cost or energy and environmental impacts of this process. An approximate capital investment of $2.5 million, however, is reported for a 360 Mg/day (400 ton/day) plant. The electricity required for circulating scrubber reagent is about 75 kW at a circulation rate of 0.127 m3/s (2000 gpm). The hydrogen peroxide consumption is reported to be 0.5 units/unit of SO_2 removed.

5.3 LIQUID SO_2 FGD SYSTEMS

Two types of liquid SO_2 systems are discussed; the first is liquifaction by compression and the second liquification by refrigeration. Both require relatively strong SO_2 gas stream concentrations and are not amenable to weak stream treatment. A schematic diagram of liquifaction by compression is given in Figure 5.22. The compression system as discussed here is applied to a gas stream containing about 10% SO_2 and which has been cooled in a waste- heat boiler and spray tower. This represents a system applicable to the SO_2 regenerated from a magnesium oxide FGS system. The cooled stream is sent to a drying tower where concentrated H_2SO_4 (98 percent) is used to remove the remaining moisture from the gas stream. Part of the diluted acid stream is recirculated through the drying tower, and the rest is returned to the acid plant, where it is reconcentrated. The SO_2 in the gaseous stream out of the drying tower is compressed by a multistage compressor and then condensed to liquid form. The liquid SO_2 is pumped to a receiver.

The refrigeration system is discussed as applied to the SO2 regenerated from a citrate FGS system (Figure 5.25). In this case, the gas is by weight about 98% SO_2 and 2% water. The gas stream from the stripper condenser contains a high concentration of SO_2 and some water vapor. The water vapor is removed in a drying tower by scrubbing with sulfuric acid. The dry gas stream from the drying tower, which is nearly 100 percent SO_2, is sent to a Freon cooler, where the SO2 is liquified and then pumped to a receiver.

Estimated costs for these systems are given in Figures 5.23, 5.24, 5.26 and 5.27, while costs are compared in Table 5.4 for a DMA system and a physical recovery system.

5.4 ELEMENTAL SULFUR

There are a number of processes available for the production of elemental sulfur from smelter gases. Based upon experience at smelters using reduction processes, it appears that relatively high concentrations of input SO_2 gas are required. Therefore, elemental sulfur production can be considered an alternative to acid or liquid SO_2 rather than a control technology for weak SO_2 off-gases. In addition, these processes require the use of a fossil fuel as a reductant and therefore are considered uneconomical. For this reason, cost estimates for these systems are not provided. However, it may be possible to acquire a relatively cheap reductant from a fuel desulfurization or cool gasification plant in place of the fossil fuel and achieve an economical operation, where smelter siting permits. A generalized process diagram is shown in Figure 5.28.

TABLE 5.1
Sulfuric Acid Production Processes

Acid Plants		Concentration				
		Inlet (%)		Outlet (ppm)	Efficiency	Acid strength
Process	Type	Minimum	Optimum			
Single Contact	Contact (S, M)	3.5	7.0	2500	98	98
Double Contact	Contact (S, M)	4.5	9.0	500	99.7	98
CIL (Canadian Industries, Limited)	Contact (S)	?	?	< 500	99.7	98+
Ugine Kuhlmann	Contact (S)	?	12.0	200-500	99.85	99.5
Ciba-Giegy	Chamber (M)	1-4	?	< 200	99.5	75
Browder	Contact (M)	1.5	?	< 500	98	93
Westinghouse	Electrolysis (P)	90	?	> 10	99+	30-60
Kernforschungsanlage	(P)	> 0.1	-	0.1	?	50

(S) Sulfur burning plant; (M) Metallurgical off-gas; (P) Power plant off-gas

<u>Process Descriptions</u>

CIL: Single absorption plant practising absorption of unconverted SO_2 in the absorption tower followed by recycling to the drying tower wher it is stripped into the incoming gas stream. Status: unknown

Ugine Kulhlman: Double absorption pressure process. Status: full-scale plant in France

Ciba-Giegy: Chamber process in which nitrosylsulfuric acid is formed and the NO_2 is stripped out to leave the sulfuric acid. Status: Small, full-scale plant on inolybdenum sulfide roaster in Germany

Browder: Single absorption using heat recovered from the reverb furnace off-gas in place of natural gas. Status: Conceptual, based upon existing technology

Westinghouse: Low temperature electrochemical cell reaction $2\ H_2O + SO_2 \rightarrow H_2SO_4 + H_2$; H_2 can be used as fuel or as reductant to produce elemental sulfur. Status: in research lab

Kernforschungsanlage: Absorption of SO_2 by weak sulfuric acid; the SO_2 in the liquor is converted to SO_2 by a catalyst consisting of an activated coal and absorbed in the liquor. Status: applied to power plant effluent

TABLE 5.2

Capital and Operating Cost of a Single Contact Acid Plant ($Can June, 1979)

Basis for Estimates	Continuous Gas only	Variable Gas only	Continuous Gas Base Load with Variable Gases	
Production: t/day 100% H_2SO_4	530	530	530	1 070
Gases:				
Continuous smelter gas, i.e., from roaster, flash furnace, % SO_2	12	-	12	12
Variable gas, i.e., from converters, %SO_2	-	5 - 8	5 - 8	5 - 8
CAPTIAL COST ($, June 1979 cost level)				
Single catalysis sulfuric acid plant[1]	11 880 000	19 499 000	14 700 000	22 363 000
Contingency @ 25%	2 970 000	4 875 000	3 700 000	5 591 000
Auxiliary equipment and services	1 485 000	2 437 000	1 850 000	2 795 000
Total Capital Cost	16 335 000	26 811 000	20 349 000	30 749 000
PRODUCTION COST ($/t H_2SO_4)				
Operating Cost:				
Supervision	0.54	0.54	0.54	0.26
Operating labour	1.06	1.06	1.06	0.60
Utilities[2]	1.61	2.86	2.01	1.97
Operating supplies[3]	0.28	0.28	0.28	0.28
Maintenance[4]	2.89	4.74	3.59	2.37
Indirect cost[5]	0.71	0.71	0.71	0.37
Subtotal	7.09	10.19	8.19	6.21
Contingency @ 10%	0.71	1.02	0.82	0.62
Total operating cost	7.80	11.21	9.01	6.83
Capital Charges				
Amortization and Interest @ 15 years and 10%/yr	11.51	18.88	14.33	10.82
Total Production Cost	19.31	30.09	23.34	17.65

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[1] Includes engineering and construction overhead costs

[2] Includes natural gas, water and electric power

[3] Includes limestone for weak acid neutralization and other operating supplies

[4] @ 3.3%/year of total capital cost

[5] Includes property taxes, insurance, legal and technical counsel, etc.

t = tonne

Reference: EPS-3-AP-79-8

TABLE 5.3

Flue Gas Scrubbing Systems Employed at Smelters

FGS System	Smelter	Process Emission
Lime/Limestone	Onahama, Japan - Cu	reverb furnace
	Naoshima, Japan - Pb/Zn	blast furnace sinter machine
	Hosokura, Japan - Pb/Zn	blast furnace
	Chirigirishima, Japan - Pb	blast furnace sinter machine
	Duval, Sierrita, USA - Mo	Moly roaster
Magnesium Oxide	Onahama, Japan - Cu	reverb furnace
Ammonia	Cominco, Canada - Pb/Zn	sinter machine zinc roaster
Cold Water	Boliden, Sweden - Cu	reverb furnace
DMA	ASARCo, USA - Cu	strong SO_2
	Citres Services, USA - Cu	strong SO_2

TABLE 5.4

Cost of Recovering Liquid Sulfur Dioxide from Smelter Gases
($Can. June, 1979)

Basis For Estimates	Chemical Absorption Process (ASARCO's Dimethyl Aniline Process)	Physical Recovery Process (Compression & Referigeration)
Production:		
160 t/day liquid SO_2, corresponding to 56 000 t annually (assuming 350 operating days)		
Gas processed:		
Smelter gases with 12% SO_2, cleaned in hot electrostatic preciptator		
CAPITAL Cost ($June 1979 cost level)		
Liquid SO_2 plant[1]	7 103 000	6 314 000
Contingency @ 25%	1 778 000	1 578 000
Total Capital Cost	8 881 000	7 892 000
PRODUCTION COST	\$/t SO_2	\$/t SO_2
Operating cost		
upervision	0.75	0.75
perating labour	3.45	3.45
tilities[2]	9.85	9.04
perating supplies[3]	3.83	0.98
aintenance[4]	7.13	6.34
ndirect costs[5]	1.36	1.36
oyalties[6]	0.63	—
ubtotal	27.00	21.11
ontingency @ 10%	2.70	2.19
tal Operating Cost	29.70	24.11
apital Charges Amorization interest @ 15 years and 0% year	20.43	18.15
tal Production Cost	50.13	42.26

ncludes engineering and construction overhead costs

ncludes steam, water and electric power

ncludes chemicals and other operating supplies

4.6%/year of total capital cost

ncludes property taxes, insurance, legal and technical counsel, etc.

oyalties payable for propriety process

tonne

erence: EPS-3-AP-79-8

TABLE 5.5

Energy, Capital Cost, and Sulfur Containment Data for Alternate Technologies

Technology	Estimated maximum sulfur containment	Capital cost percent of base case	Energy requirements percent of base case, (quantiy MM Btu/ton of anode)		
			Pitt and Wadsworth	Kellogg and Henderson	Other
Green feed reverb	52	90[e]	116 (30.5)	118 (18.5)	106(26.5)
Calcine feed reverb (Base case)	86-93	100	100 (26.2)	100 (15.6)	100 (25.1)
Electric furnace	94-95	100[e]	106 (27.8)	156 (24.3)	112 (28.2)
Outokumpu Flash Furnace (O_2)	94-95	70-80[e]	62 (16.3)	79 (12.3)	56 (14.0)
INCO Flash Furnace	94-95	70-80[e]	67 (17.7)	64 (9.9)	
Noranda	94-95	70-80[e]	74 (19.3)	79 (12.3)	53 (13.3)
KIVCET	94-95	70-80			78 (19.7)[e]
Mitsubishi	98-99+	70-80	78 (20.4)	90 (14.0)	
QS	98-99+	70-80[e]	68 (17.9)		
WORCA	98-99+	70-80			78 (19.7)[e]

[e] Estimated

Sulfur containment range estimates based upon: 5 to 6% total sulfur entering smelter lost as fugitives during slag and metal tapping and converter operation; single absorption acid plant efficiency of 98% and double absorption acid plant efficiency at 99.7%; calcine feed reverb range is affected by assumption of amount of sulfur expelled in the furnace, i.e., from 0 to7%.

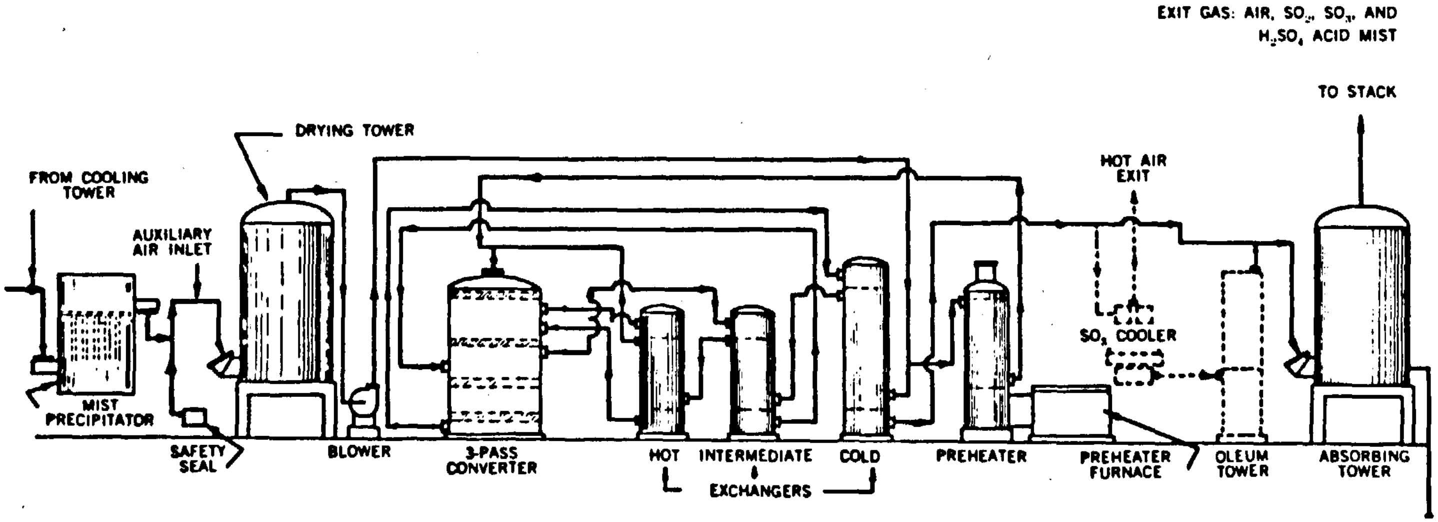


Figure 5.1 A metallurgical acid plant of the single catalyst, single absorption type

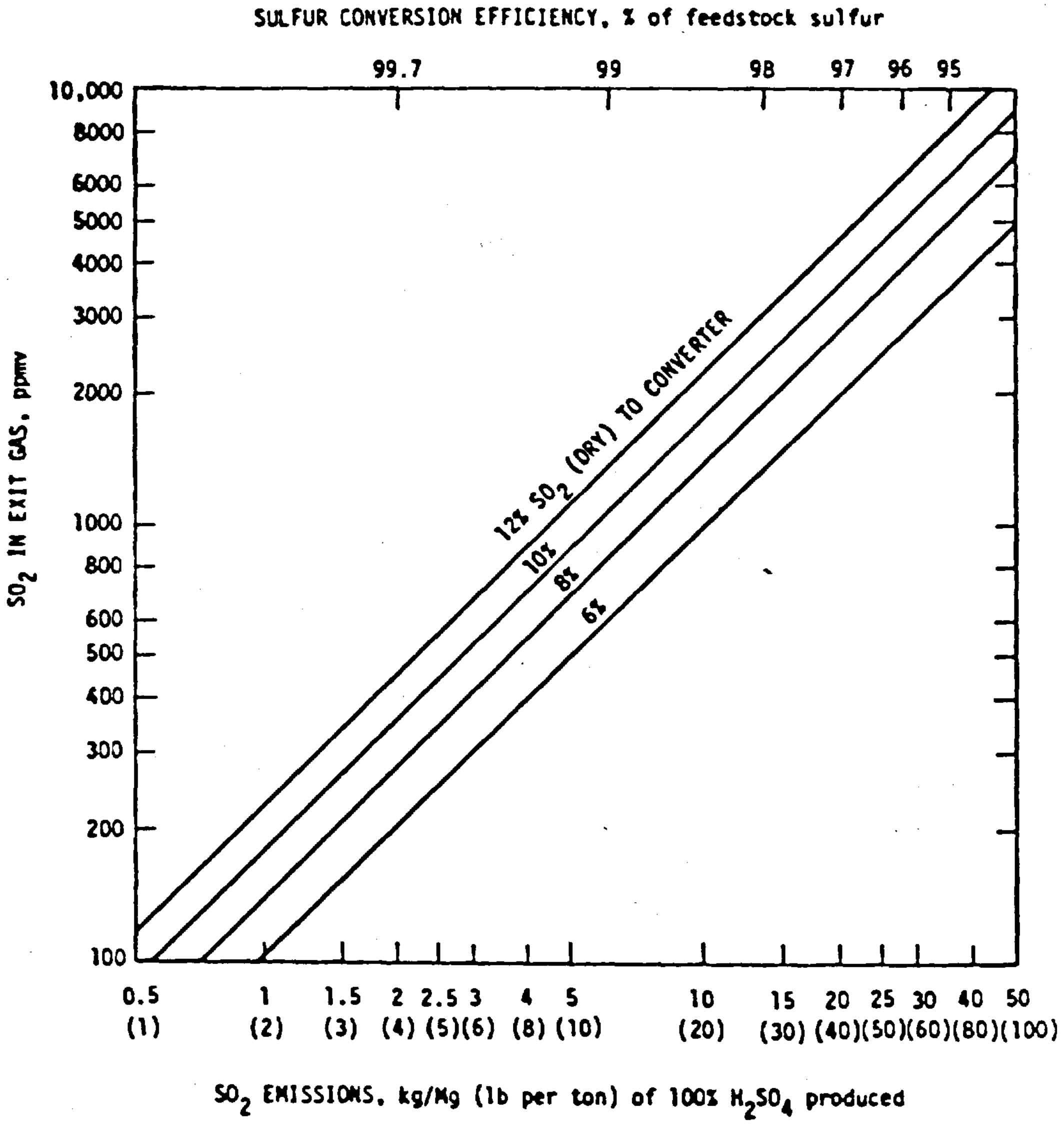
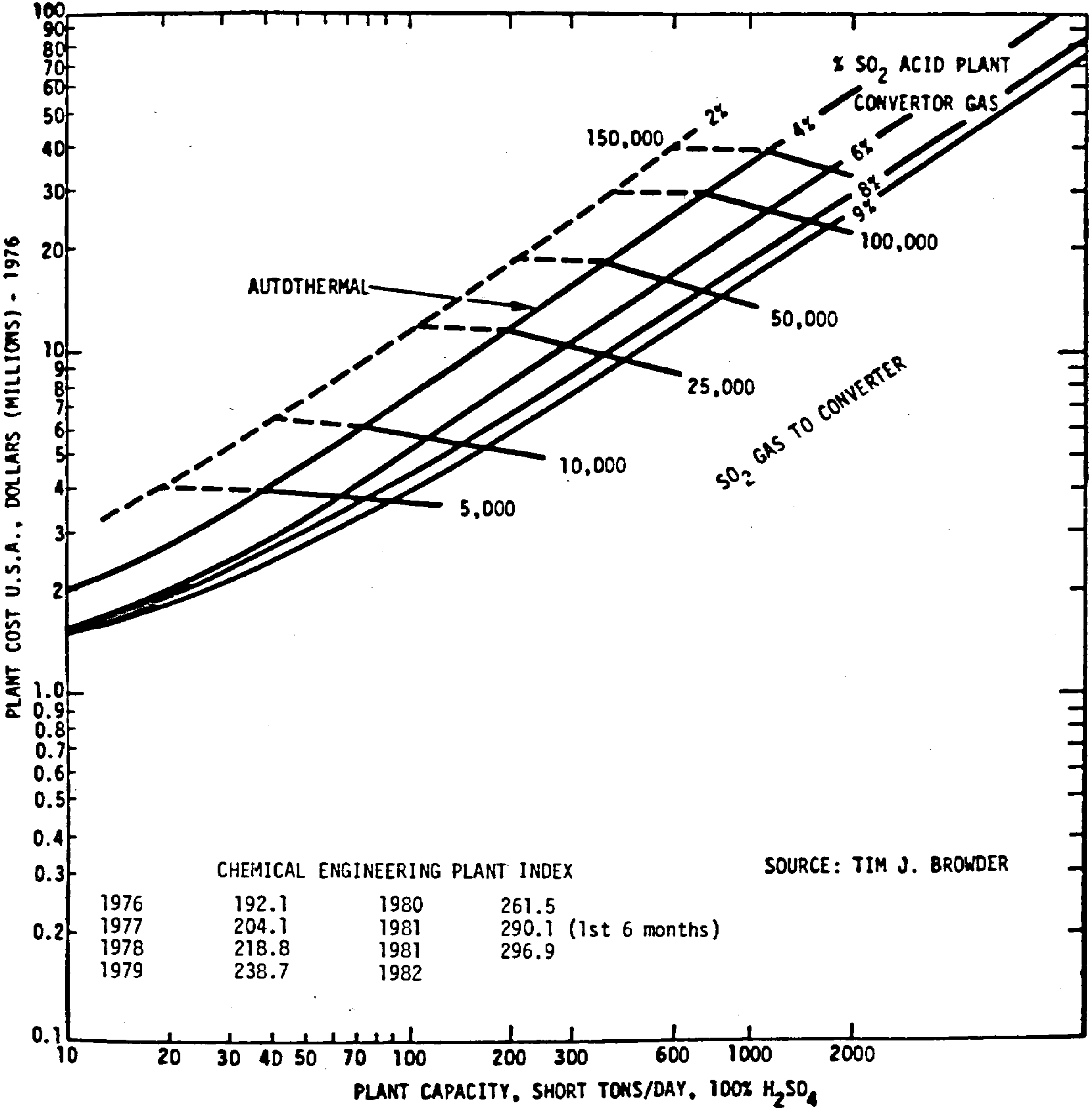


Figure 5.2 Volumetric and mass SO_2 emissions from contact sulfuric acid plants.[4]



CHEMICAL ENGINEERING PLANT INDEX

1976	192.1	1980	261.5
1977	204.1	1981	290.1 (1st 6 months)
1978	218.8	1981	296.9
1979	238.7	1982	

SOURCE: TIM J. BROWDER

Figure 5.3 Capital cost for a double contact, double absorption from sulfur acid plant for a copper smelter

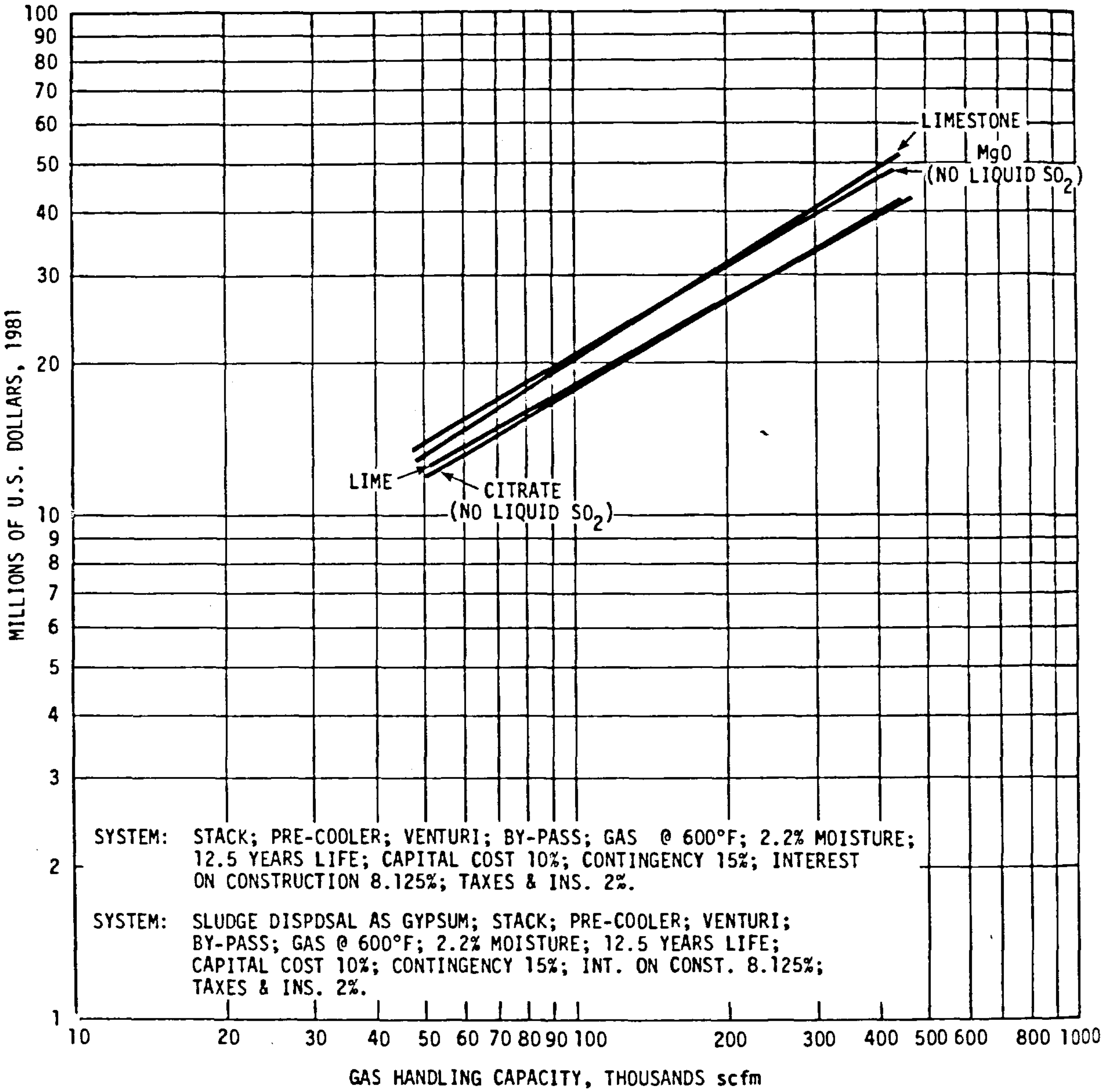
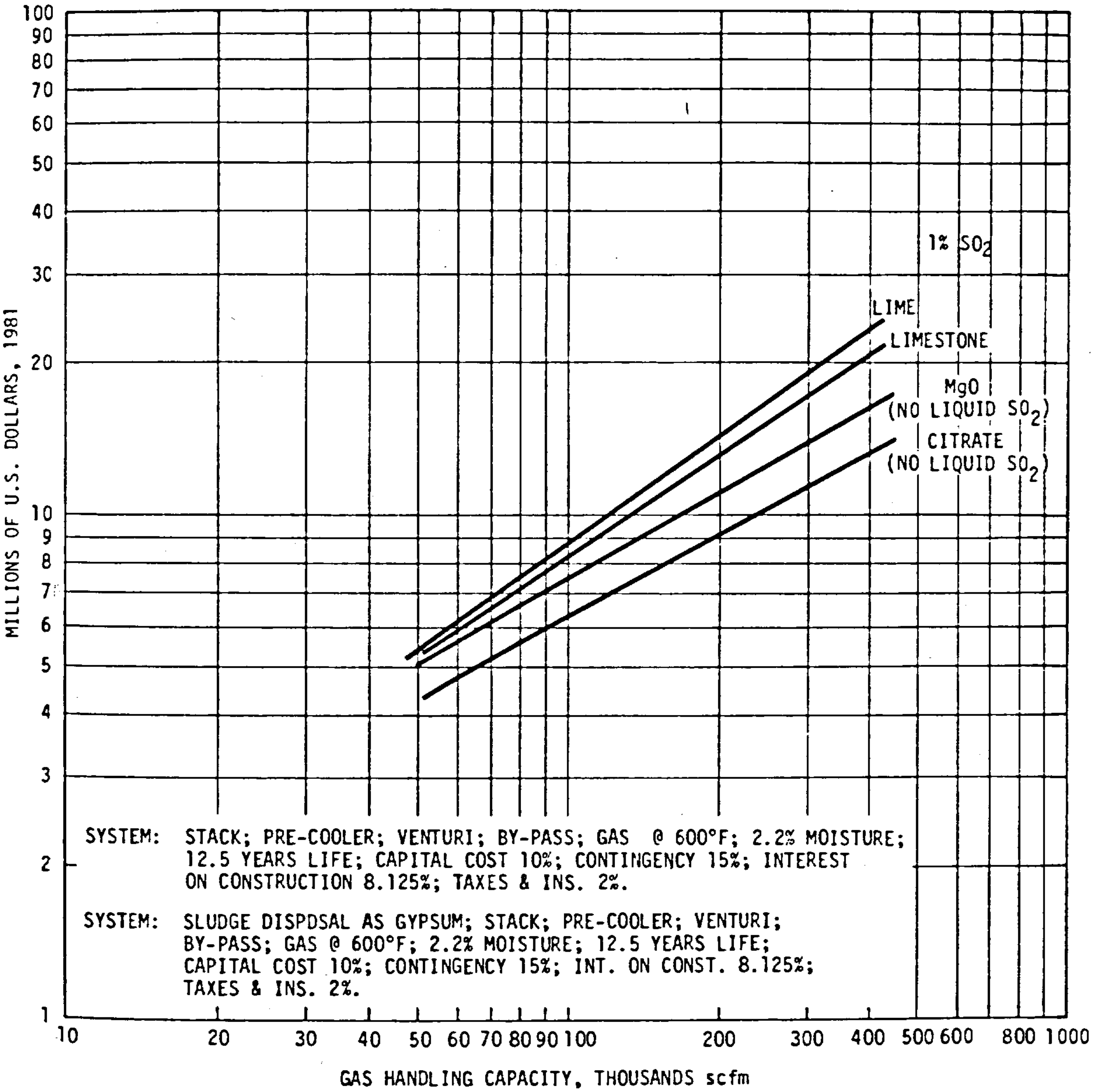


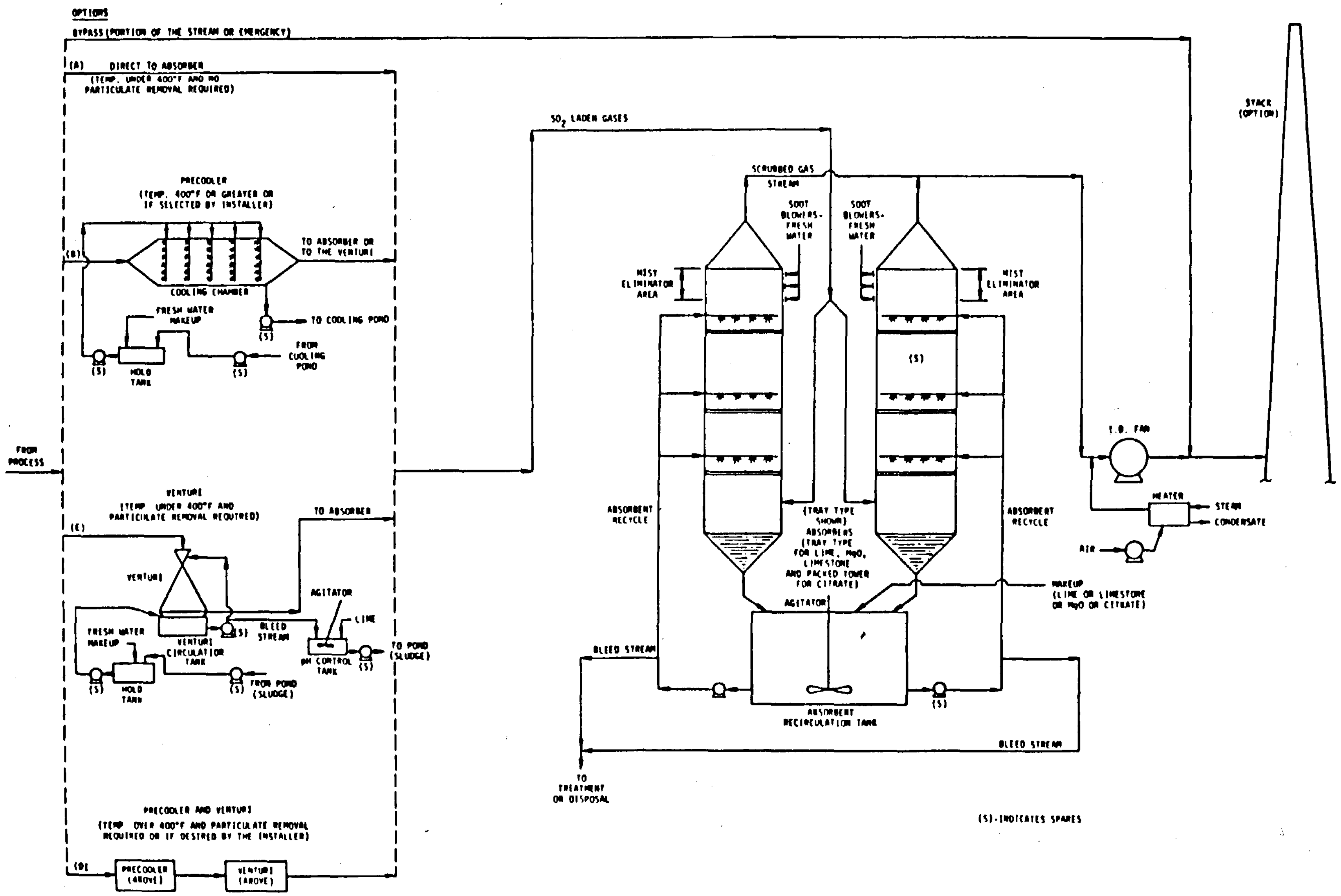
Figure 5.4 Capital cost comparison of four flue gas desulfurization systems



SYSTEM: STACK; PRE-COOLER; VENTURI; BY-PASS; GAS @ 600°F; 2.2% MOISTURE; 12.5 YEARS LIFE; CAPITAL COST 10%; CONTINGENCY 15%; INTEREST ON CONSTRUCTION 8.125%; TAXES & INS. 2%.

SYSTEM: SLUDGE DISPDSAL AS GYPSUM; STACK; PRE-COOLER; VENTURI; BY-PASS; GAS @ 600°F; 2.2% MOISTURE; 12.5 YEARS LIFE; CAPITAL COST 10%; CONTINGENCY 15%; INT. ON CONST. 8.125%; TAXES & INS. 2%.

Figure 5.5 Operating cost comparison of four flue gas desulfurization systems


OPTIONS
BYPASS (PORTION OF THE STREAM OR EMERGENCY)
(A) DIRECT TO ABSORBER
(TEMP. UNDER 400°F AND NO PARTICULATE REMOVAL REQUIRED)
PRECOOLER
(TEMP. 400°F OR GREATER OR IF SELECTED BY INSTALLER)
(B)
TO ABSORBER OR TO THE VENTURI
COOLING CHAMBER
FRESH WATER MAKEUP
TO COOLING POND
(S)
FROM COOLING POND
(S)
HOLD TANK
(S)
FROM PROCESS
VENTURE
(TEMP UNDER 400°F AND PARTICULATE REMOVAL REQUIRED)
TO ABSORBER
(E)
VENTURI
AGITATOR
LIME
FRESH WATER MAKEUP
(S)
BLEED STREAM
VENTURI CIRCULATION TANK
pH CONTROL TANK
(S)
TO POND (SLUDGE)
(S)
HOLD TANK
(S)
FROM POND (SLUDGE)
PRECOOLER AND VENTURI
(TEMP OVER 400°F AND PARTICULATE REMOVAL REQUIRED OR IF DESIRED BY THE INSTALLER)
(D)
PRECOOLER (ABOVE)
VENTURI (ABOVE)
SO2 LADEN GASES
SCRUBBED GAS STREAM
SOOT BLOWERS-FRESH WATER
SOOT BLOWERS-FRESH WATER
MIST ELIMINATOR AREA
MIST ELIMINATOR AREA
(S)
ABSORBENT RECYCLE
ABSORBENT RECYCLE
(TRAY TYPE SHOWN) ABSORBERS (TRAY TYPE FOR LIME, MgO, LIMESTONE AND PACKED TOWER FOR CITRATE)
AGITATOR
MAKEUP (LIME OR LIMESTONE OR MgO OR CITRATE)
BLEED STREAM
(S)
ABSORBENT RECIRCULATION TANK
BLEED STREAM
TO TREATMENT OR DISPOSAL
(S)-INDICATES SPARES
STACK (OPTION)
I.D. FAN
HEATER
STEAM
CONDENSATE
AIR

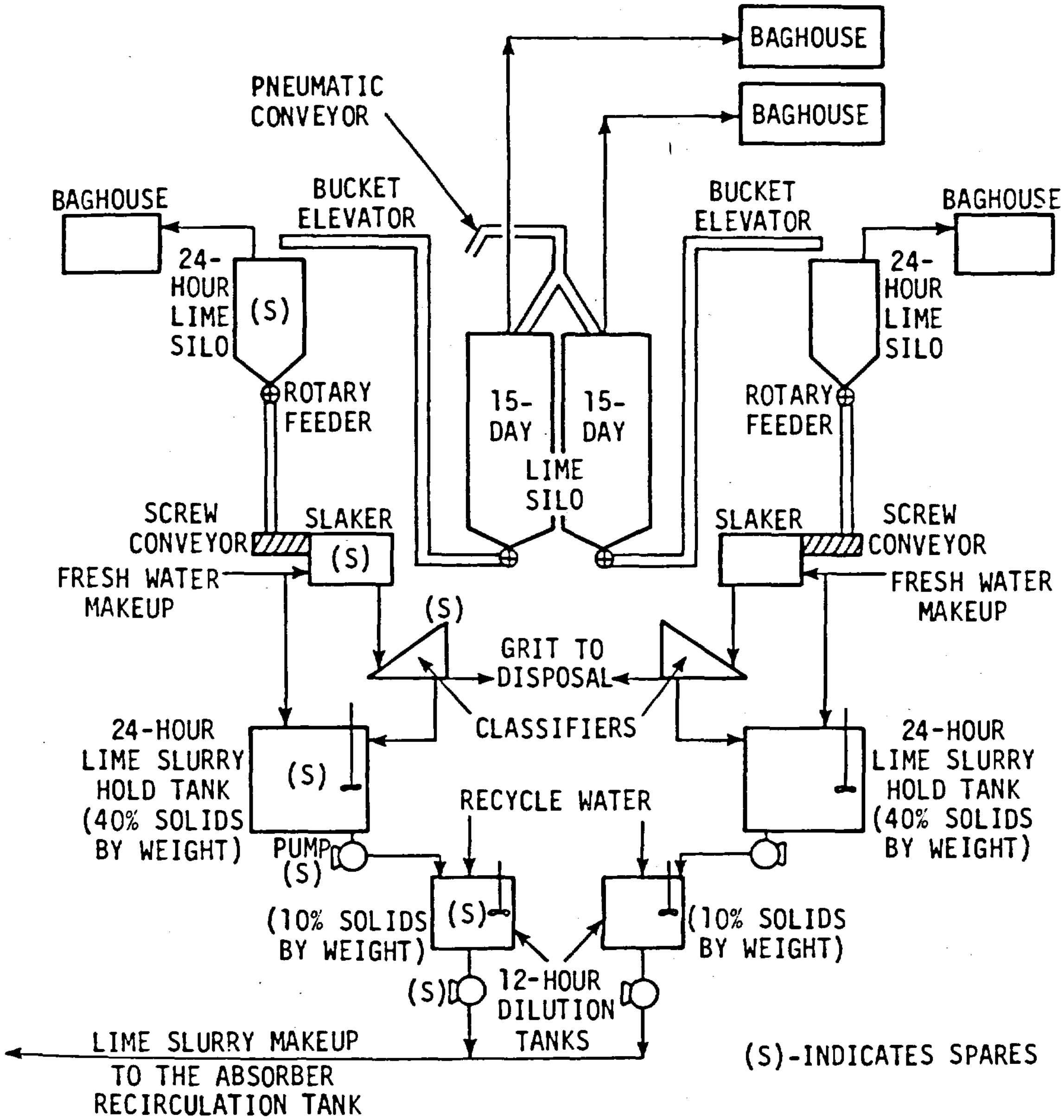


Figure 5.7 Schematic of the lime slurry makeup and storage systems

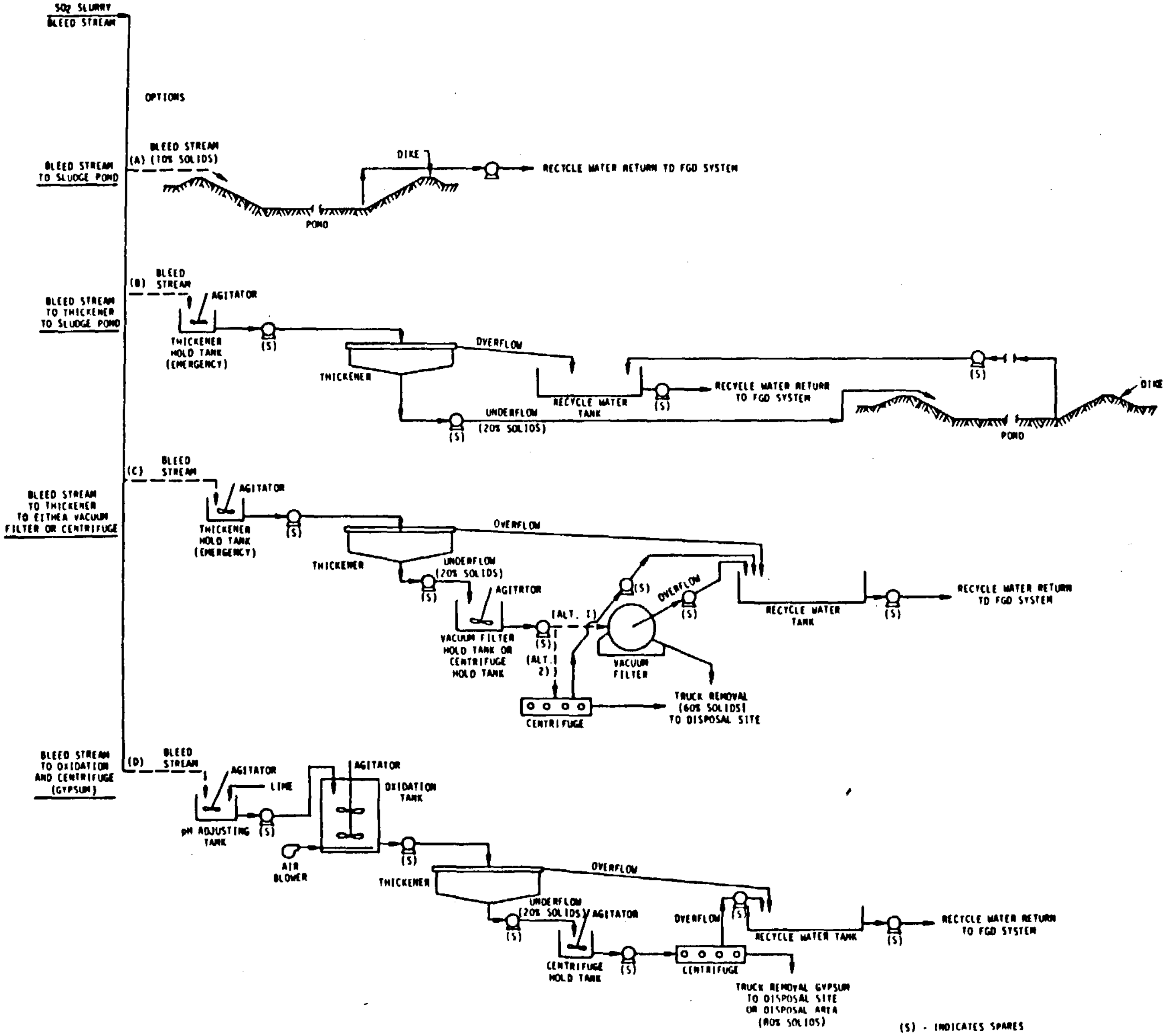


Figure 5.8 Options for the handling of the scrubber bleed stream

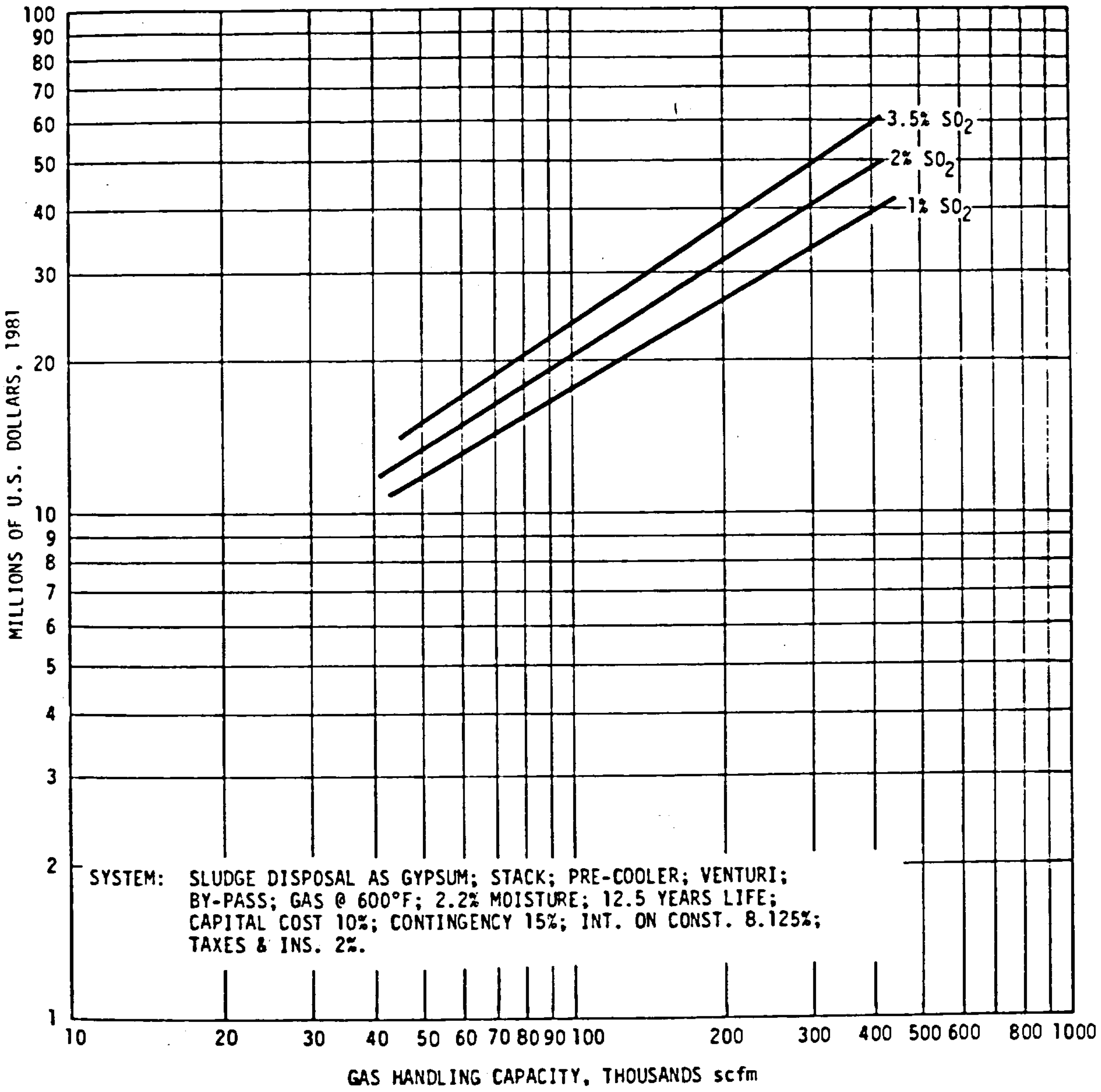
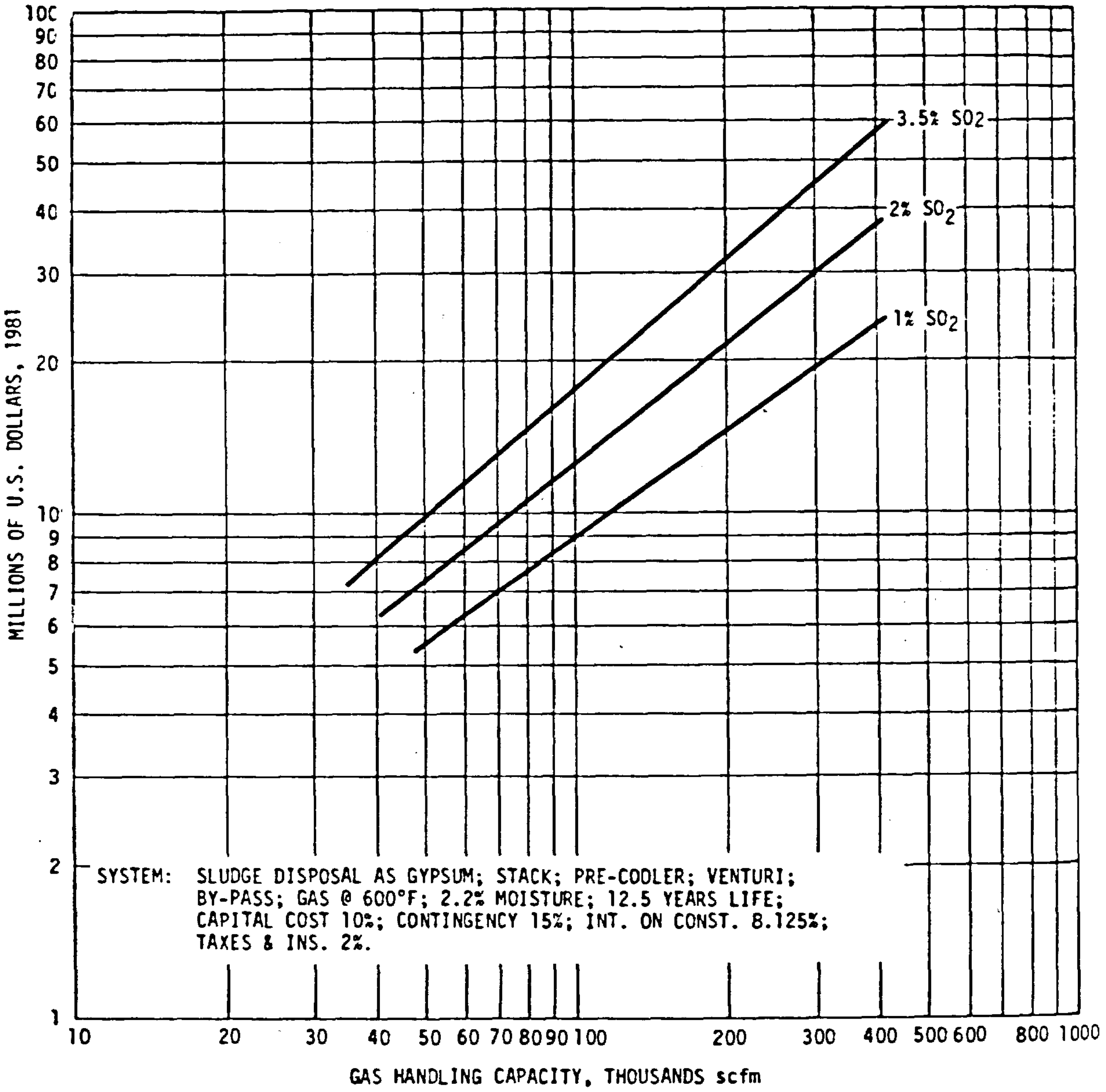


Figure 5.9 Capital cost for lime scrubbing FGD system

Figure 5.8 Options for the handling of the scrubber bleed stream



SYSTEM: SLUDGE DISPOSAL AS GYPSUM; STACK; PRE-COOLER; VENTURI; BY-PASS; GAS @ 600°F; 2.2% MOISTURE; 12.5 YEARS LIFE; CAPITAL COST 10%; CONTINGENCY 15%; INT. ON CONST. 8.125%; TAXES & INS. 2%.

Figure 5.10 Annual operating cost for lime scrubbing FGD system

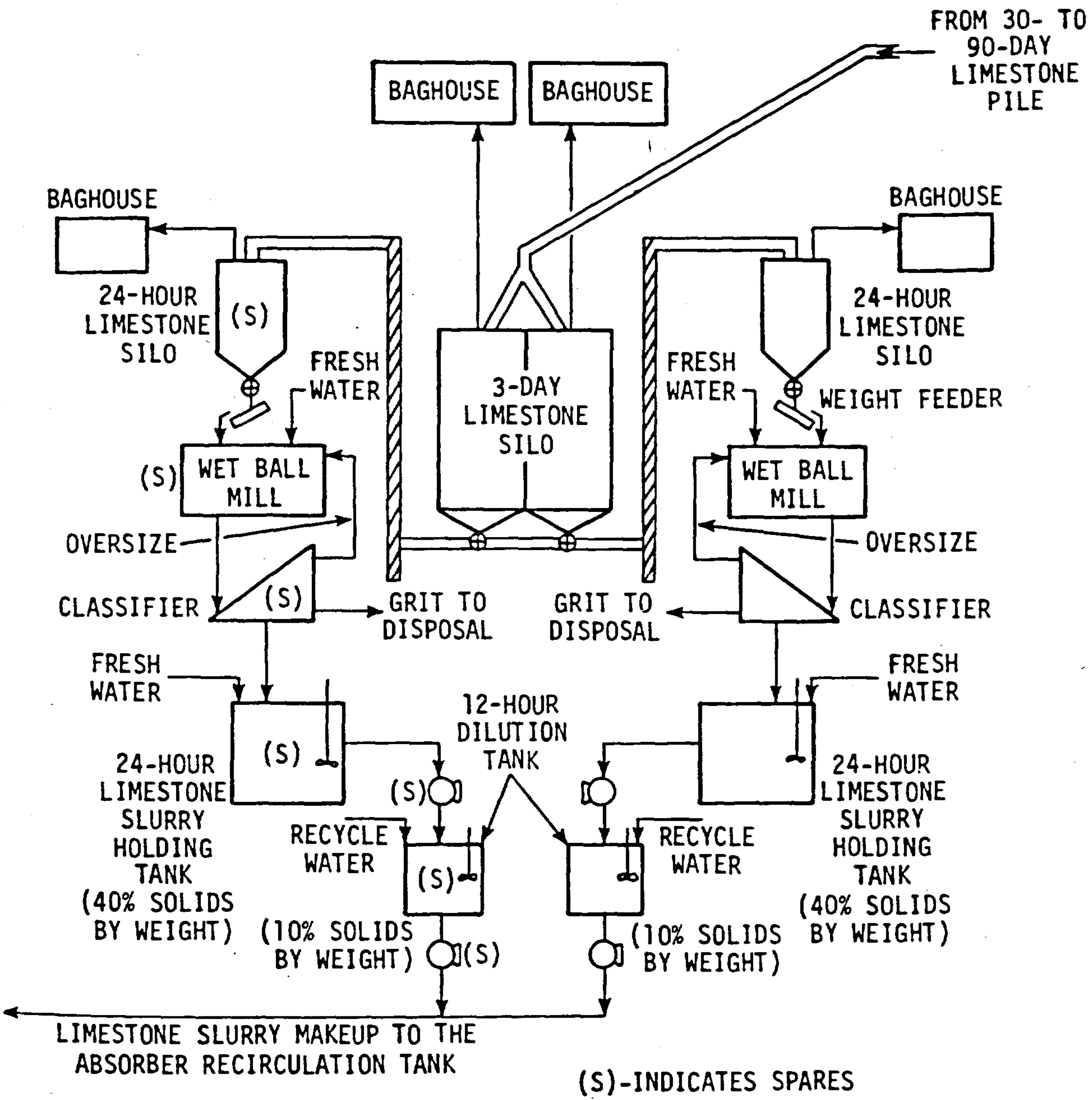
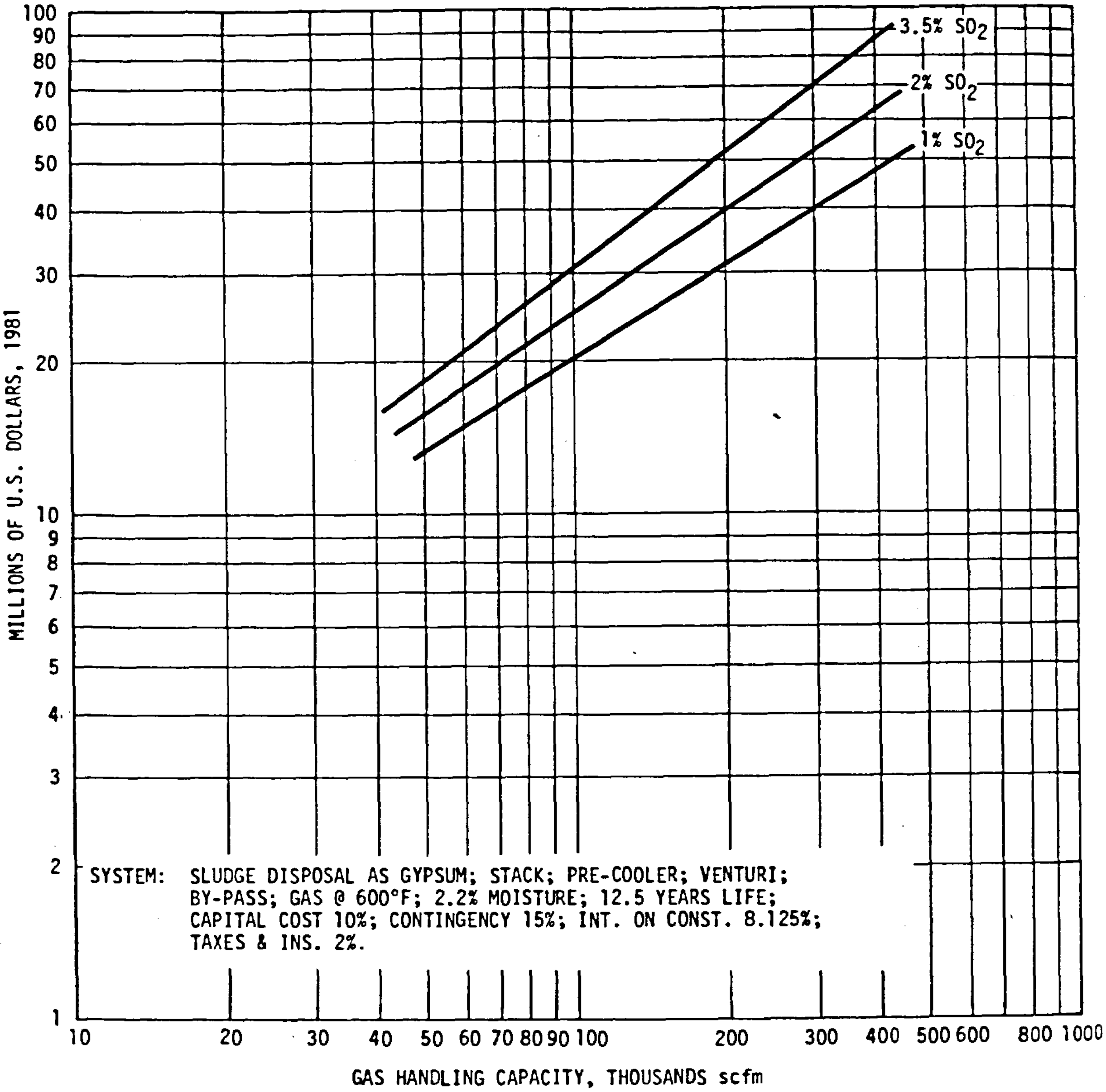


Figure 5.11 Schematic of the limestone slurry makeup and storage systems



SYSTEM: SLUDGE DISPOSAL AS GYPSUM; STACK; PRE-COOLER; VENTURI; BY-PASS; GAS @ 600°F; 2.2% MOISTURE; 12.5 YEARS LIFE; CAPITAL COST 10%; CONTINGENCY 15%; INT. ON CONST. 8.125%; TAXES & INS. 2%.

Figure 5.12 Capital cost for limestone scrubbing FGD system

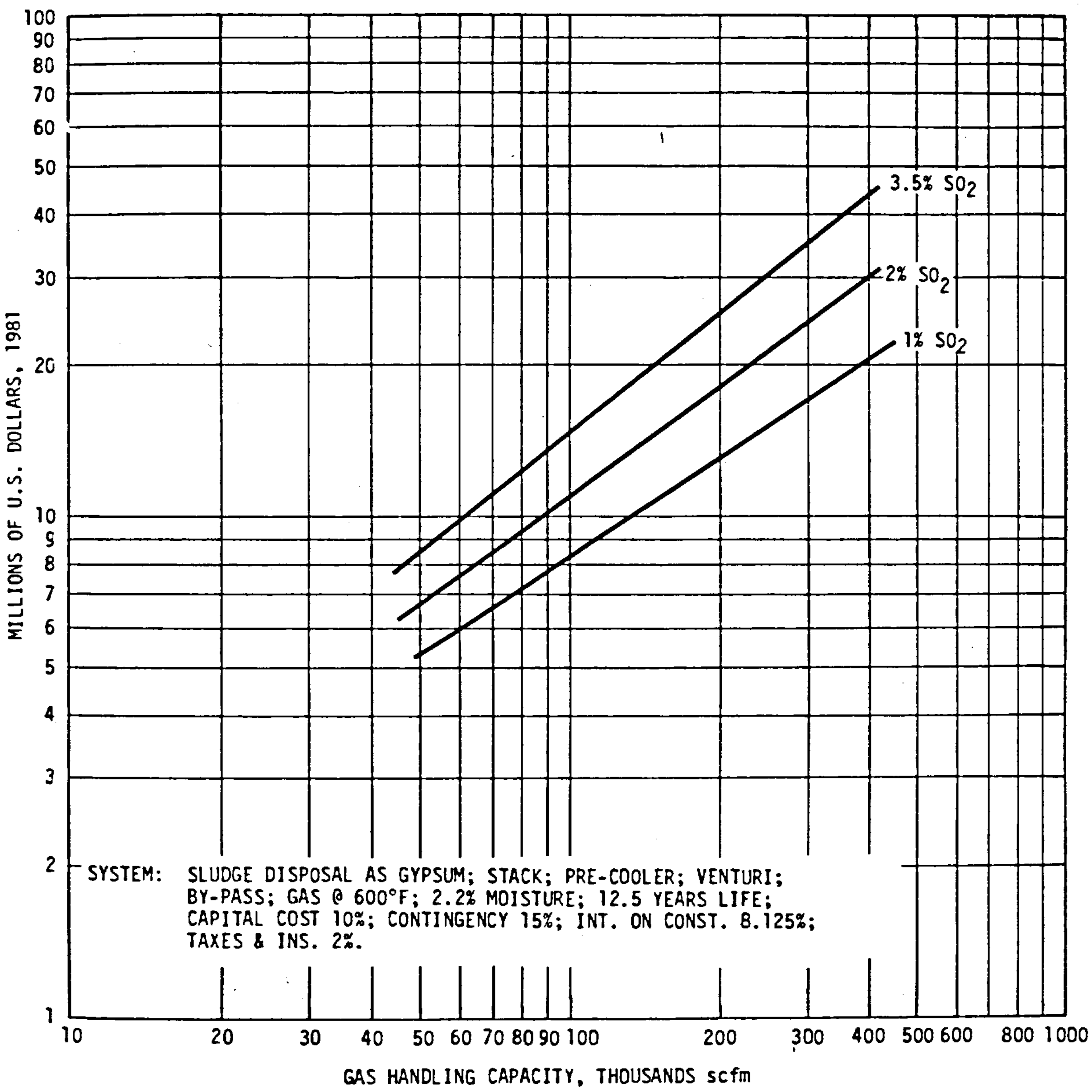


Figure 5.13 Annual operating cost for limestone scrubbing FGD system

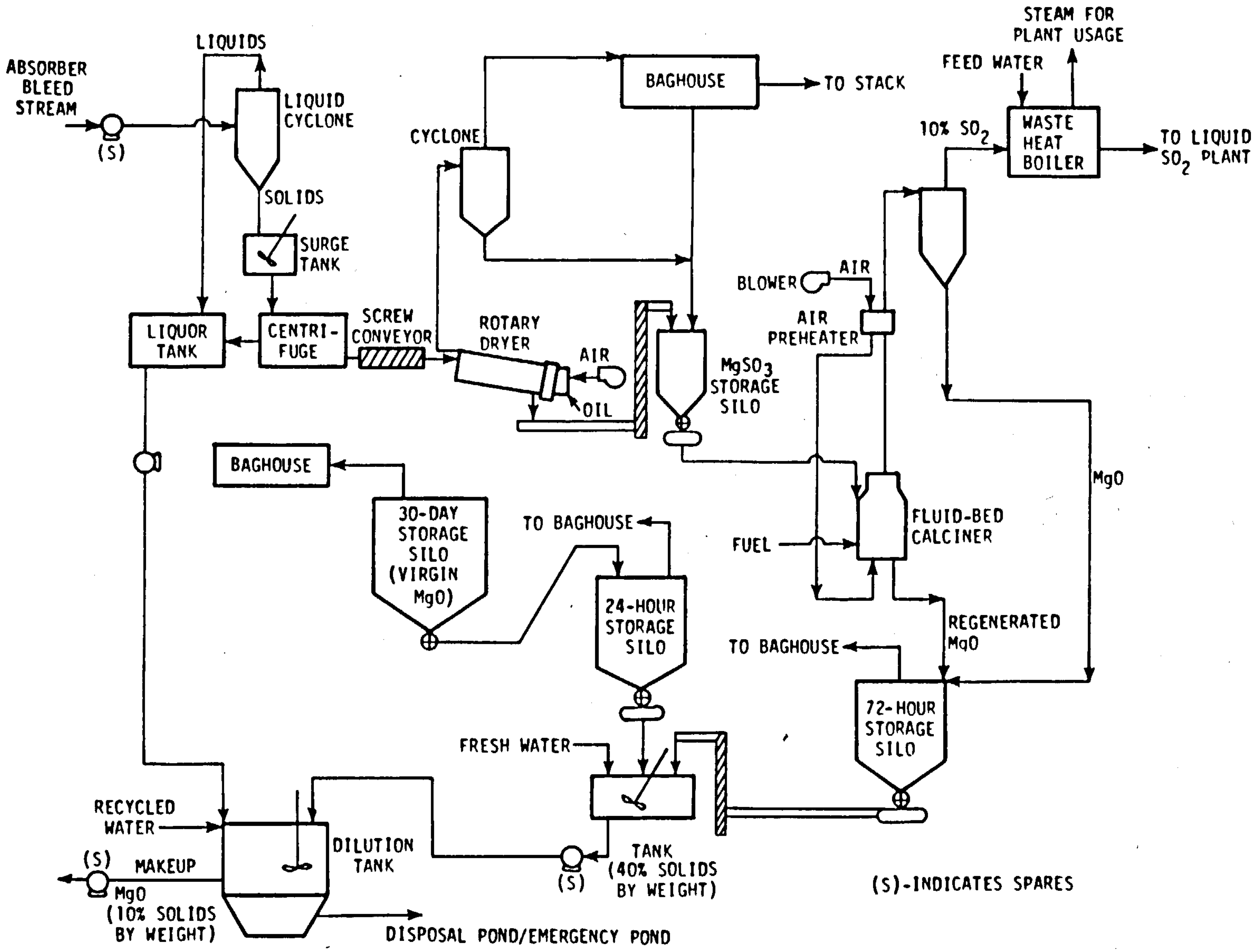
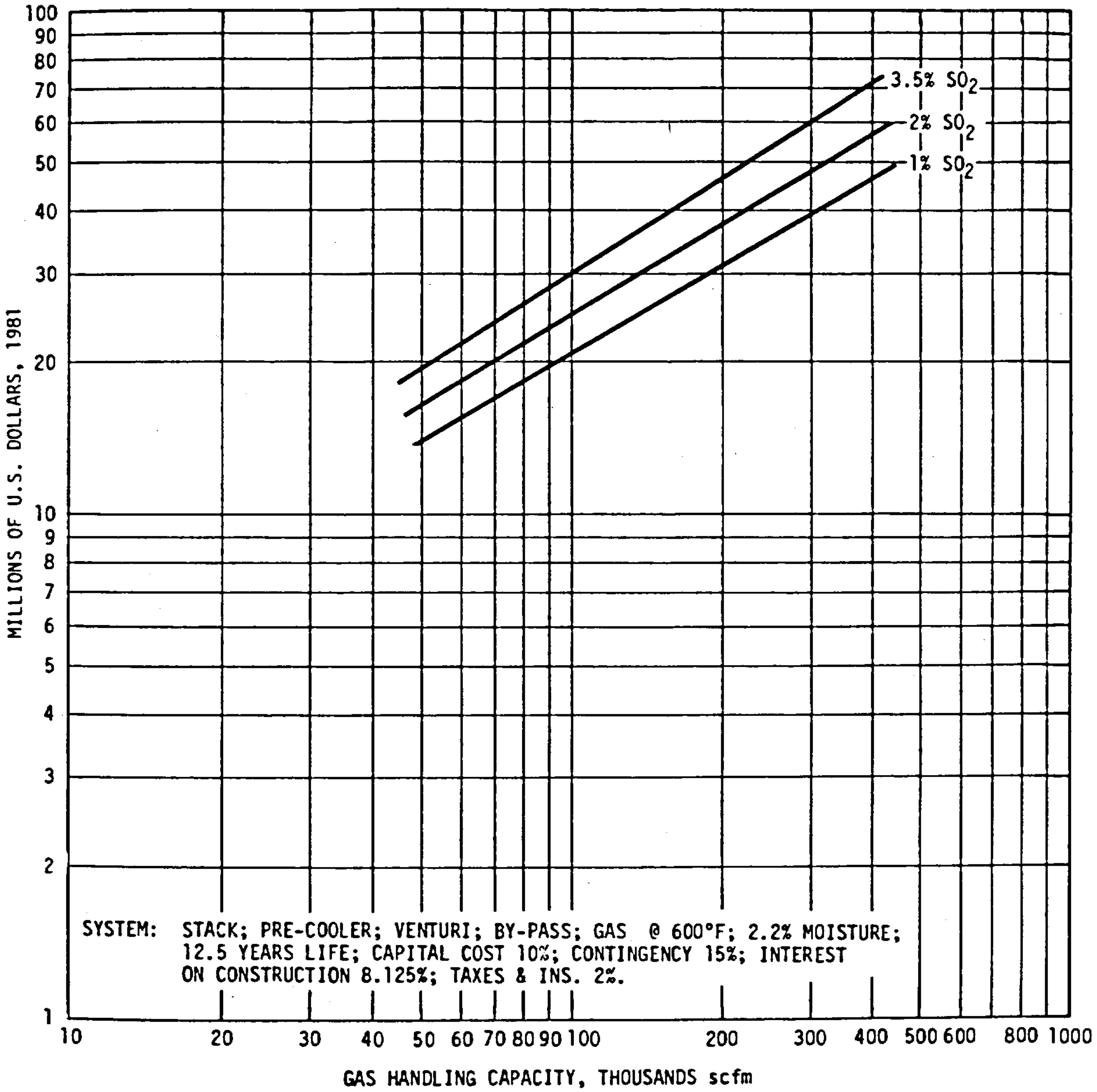


Figure 5.14 Schematic of the MgO makeup, storage, and recovery systems



SYSTEM: STACK; PRE-COOLER; VENTURI; BY-PASS; GAS @ 600°F; 2.2% MOISTURE; 12.5 YEARS LIFE; CAPITAL COST 10%; CONTINGENCY 15%; INTEREST ON CONSTRUCTION 8.125%; TAXES & INS. 2%.

Figure 5.15 Capital cost for the magnesium oxide scrubbing FGD system (without the liquid SO_2 plant)

Figure 5.14 Schematic of the MgO makeup, storage, and recovery systems

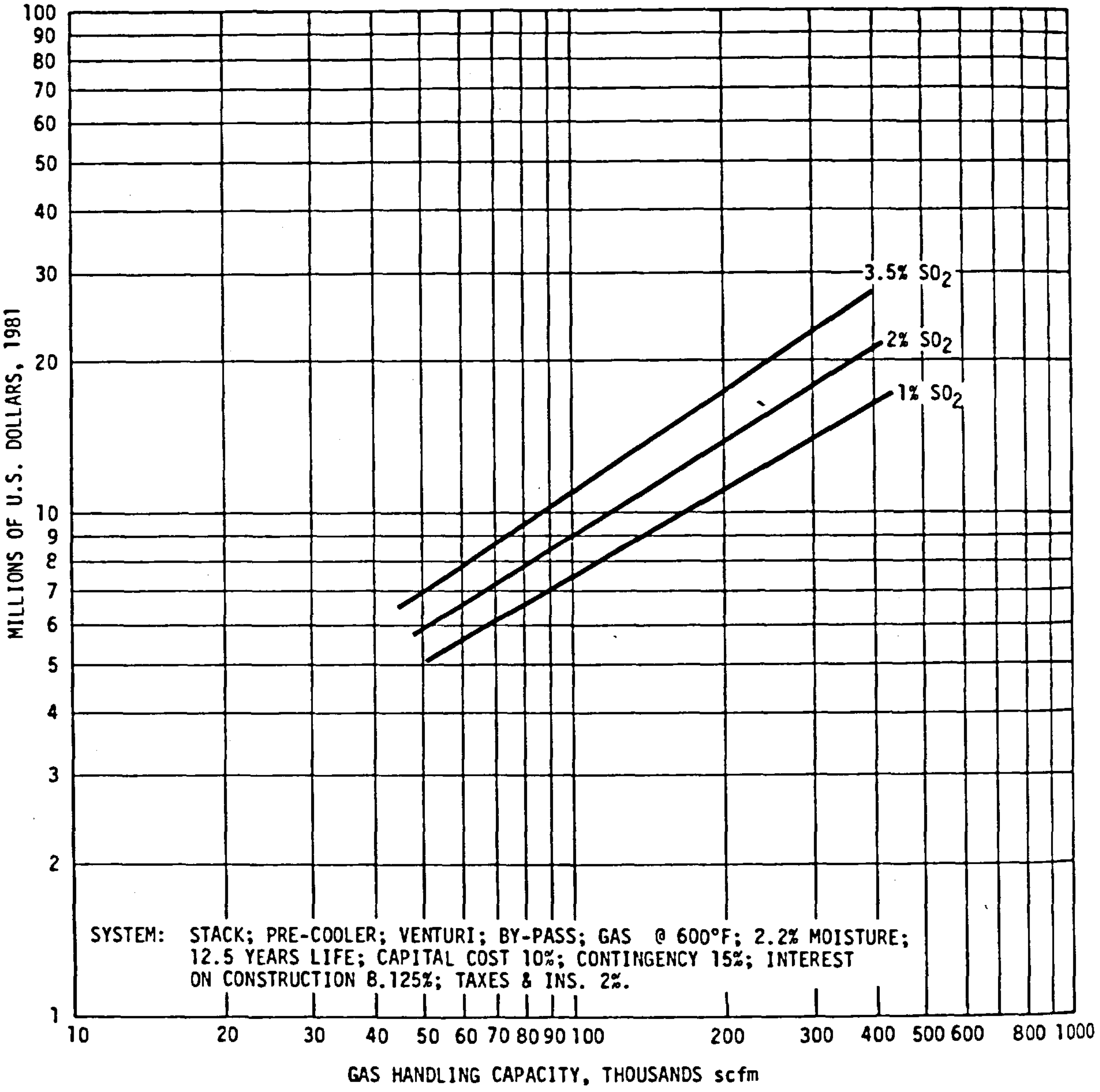


Figure 5.16 Annual operating cost for the magnesium oxide scrubbing FGD system (without the liquid SO_2 plant)

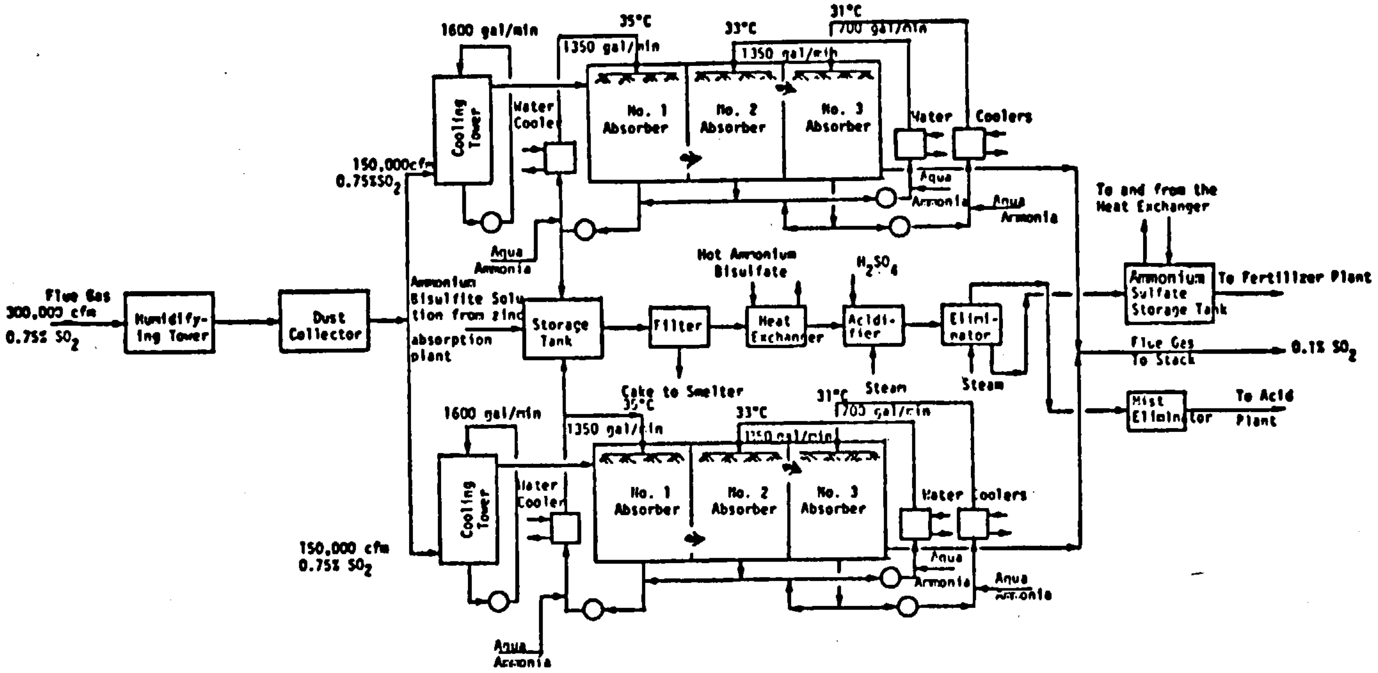


Figure 5.17 Flow diagram Cominco ammonia scrubbing process

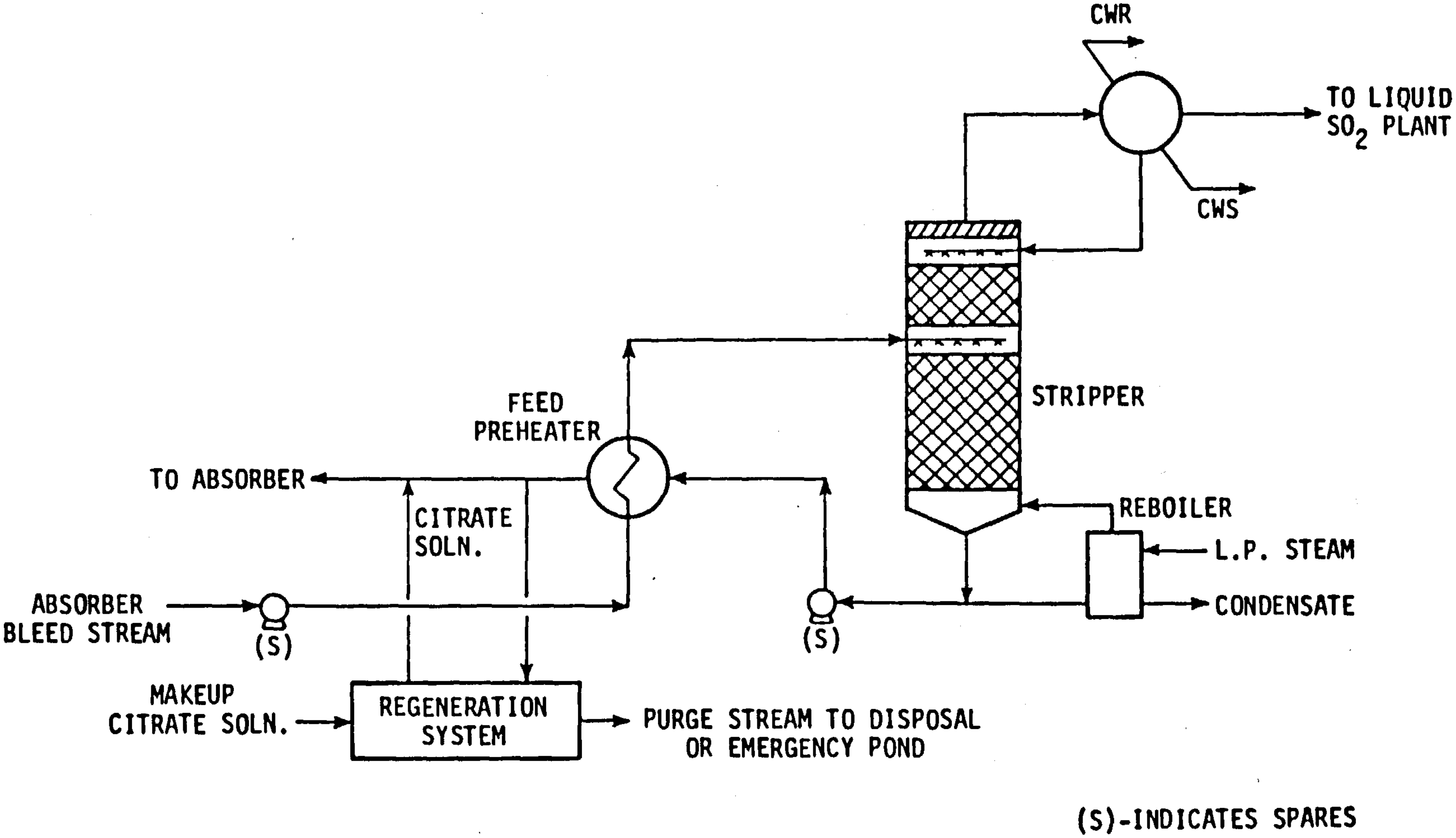


Figure 5.18 Schematic of the citrate removal and regeneration systems

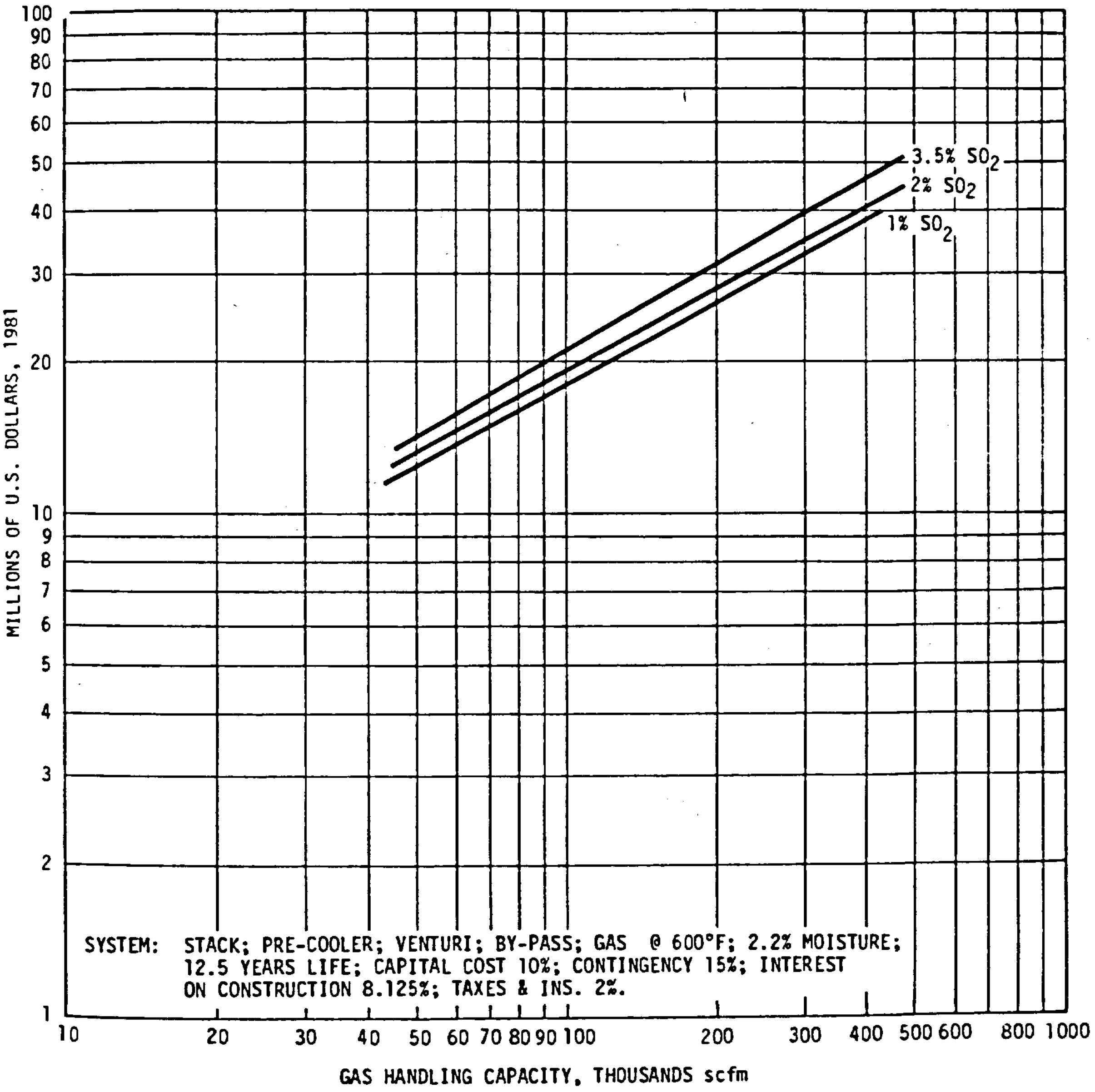


Figure 5.19 Capital cost for the Flakt citrate scrubbing FGD system (without the liquid SO_2 plant)

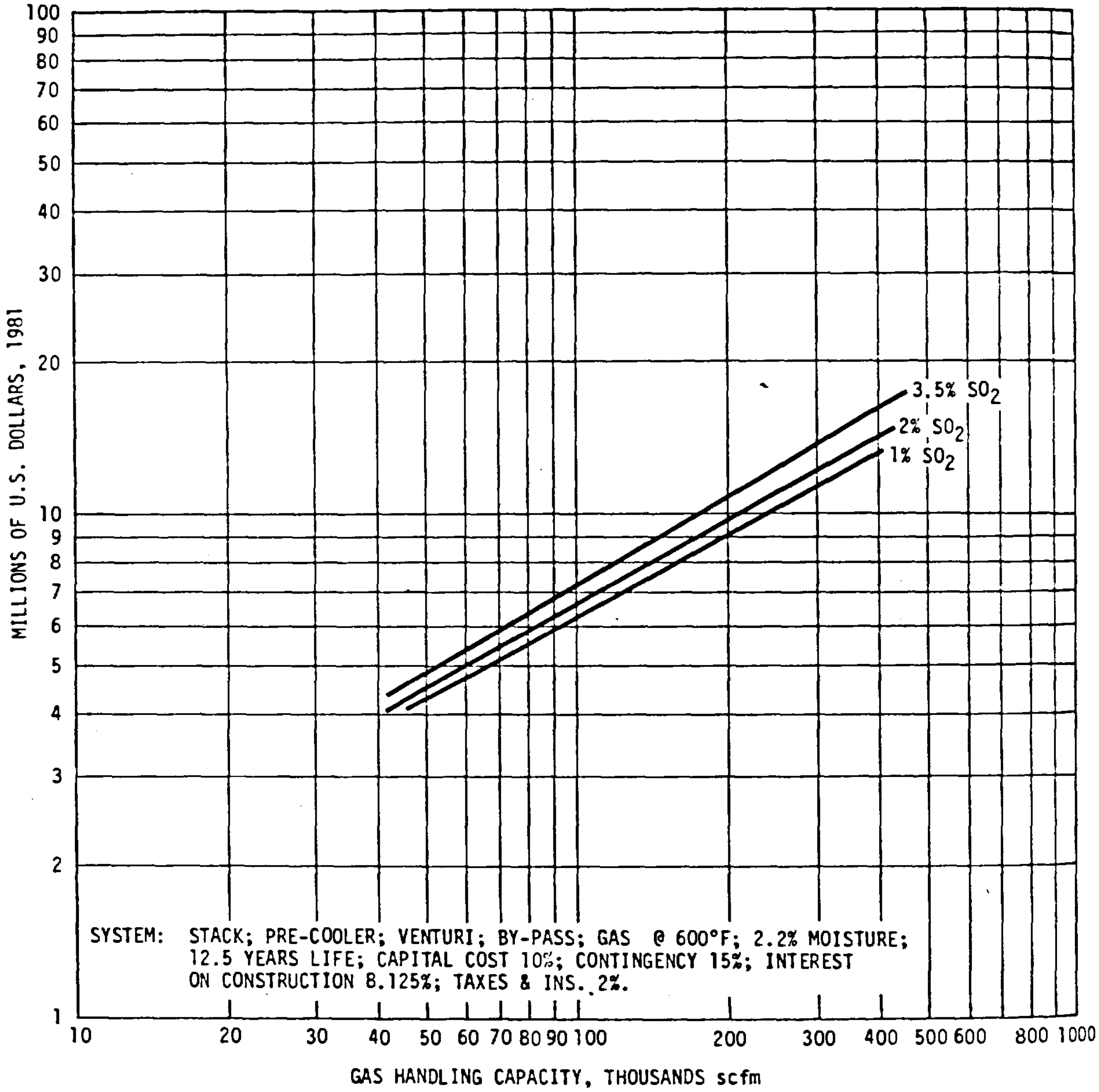


Figure 5.20 Annual operating cost for the Flakt citrate scrubbing FGD system (without the liquid SO_2 plant)

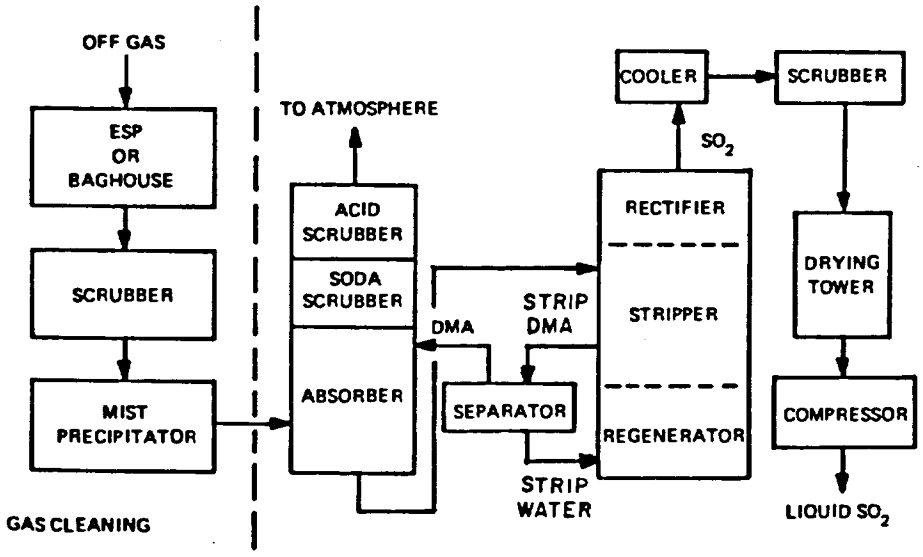
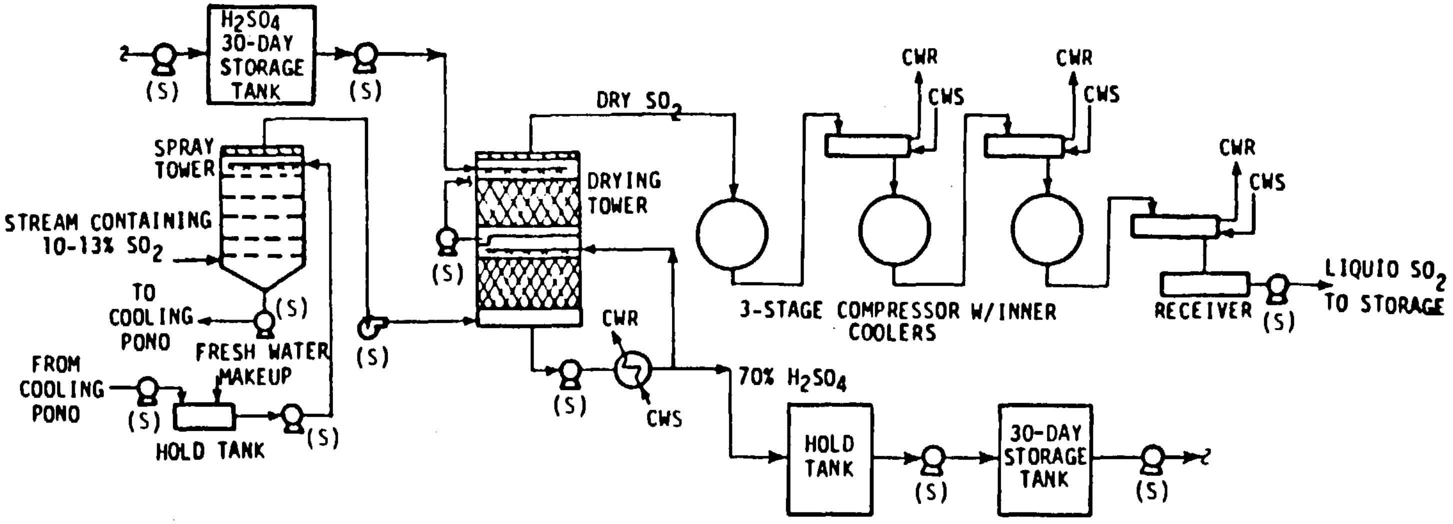


Figure 5.21 DMA scrubbing process

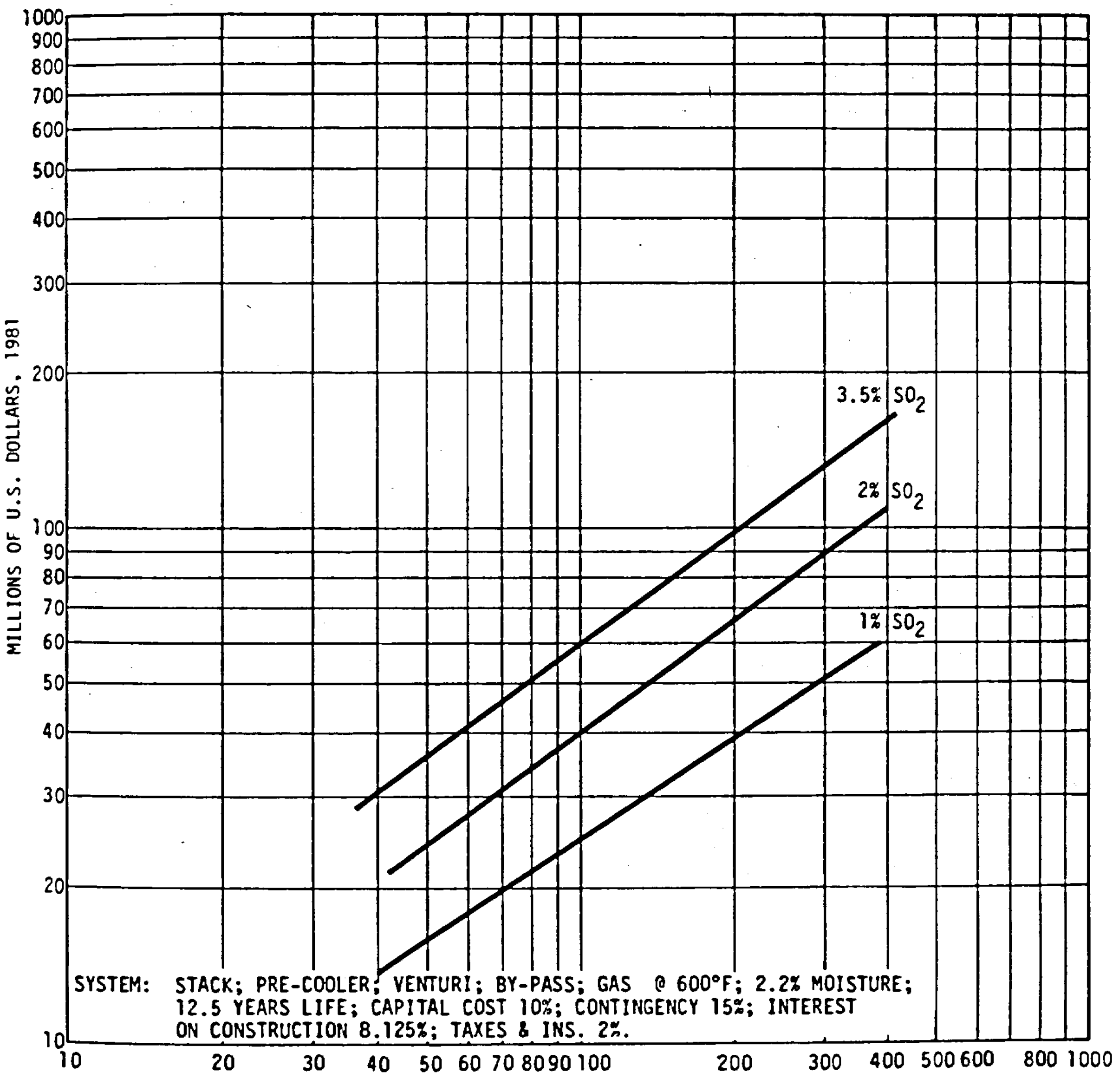
CWR - Cooling water return

CWS - Cooling water supply



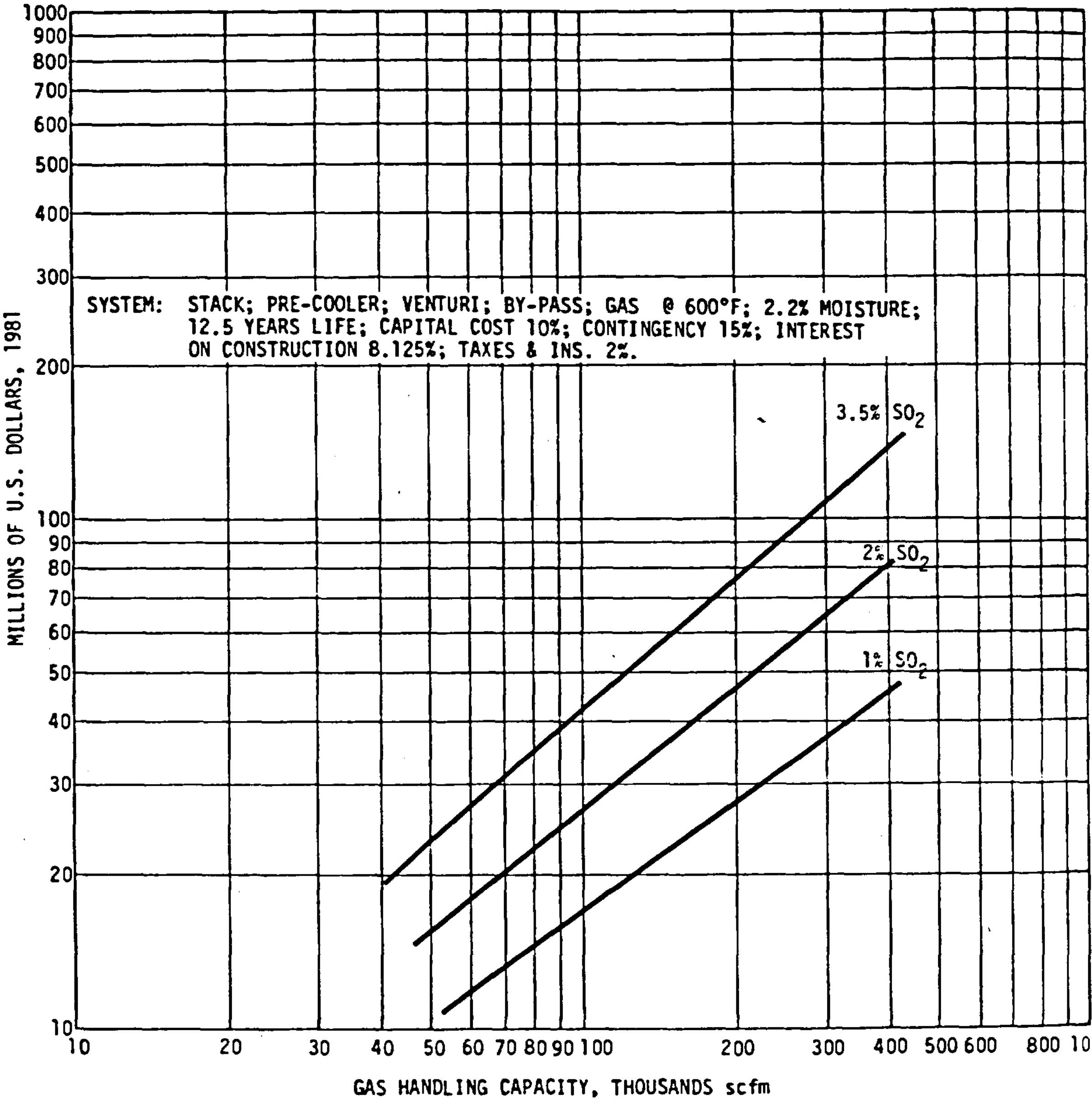
(S)-INDICATES SPARES

Figure 5.22 Schematic of the MgO liquid SO_2 and storage systems



(inlet conditions to MgO scrubbing system)

Figure 5.23 Capital cost for a liquid SO_2 plant processing concentrated SO_2 from an MgO scrubbing system



(inlet conditions to MgO scrubbing system)

Figure 5.24 Operating cost for a liquid SO_2 plant processing concentrate SO_2 from an MgO scrubbing system

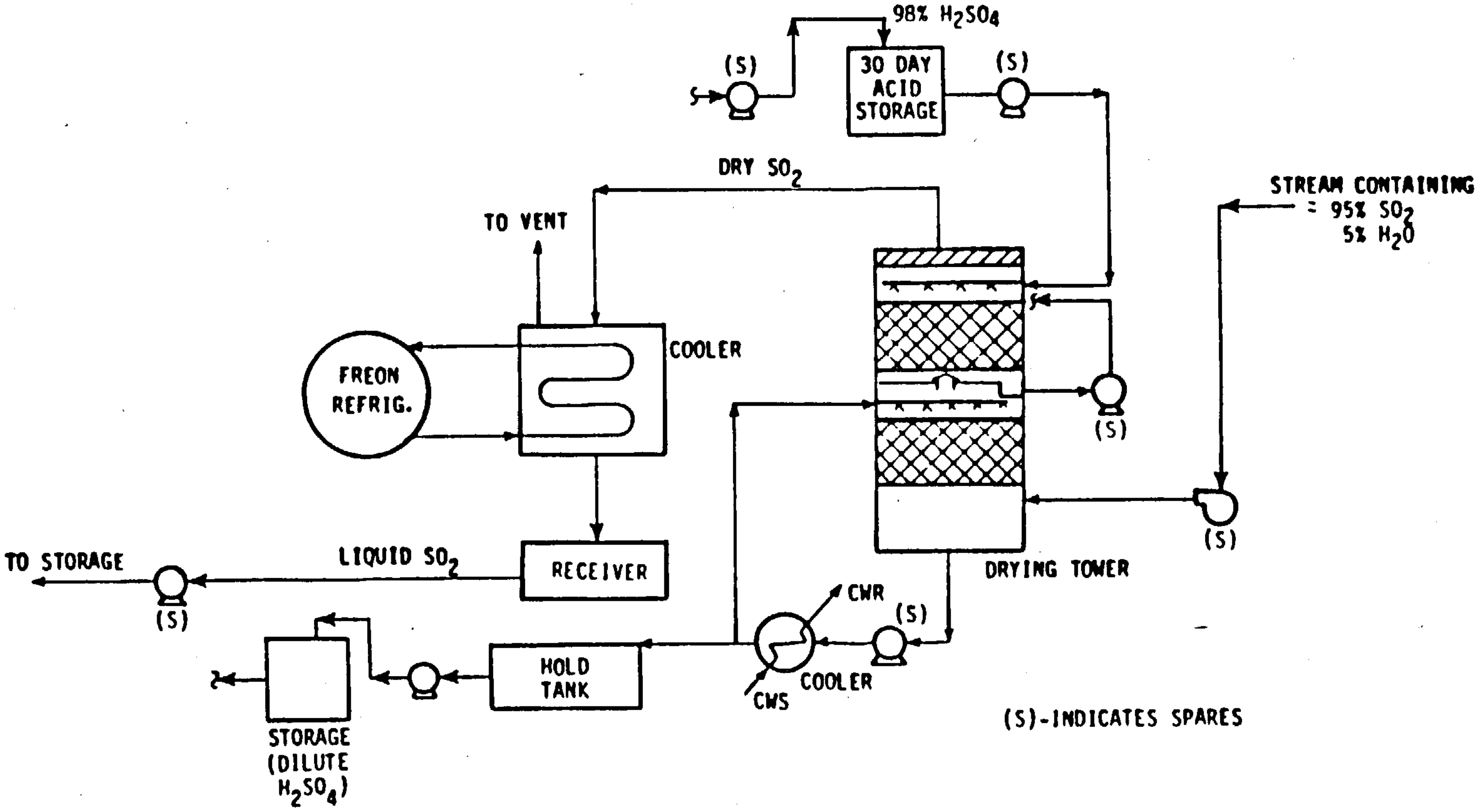
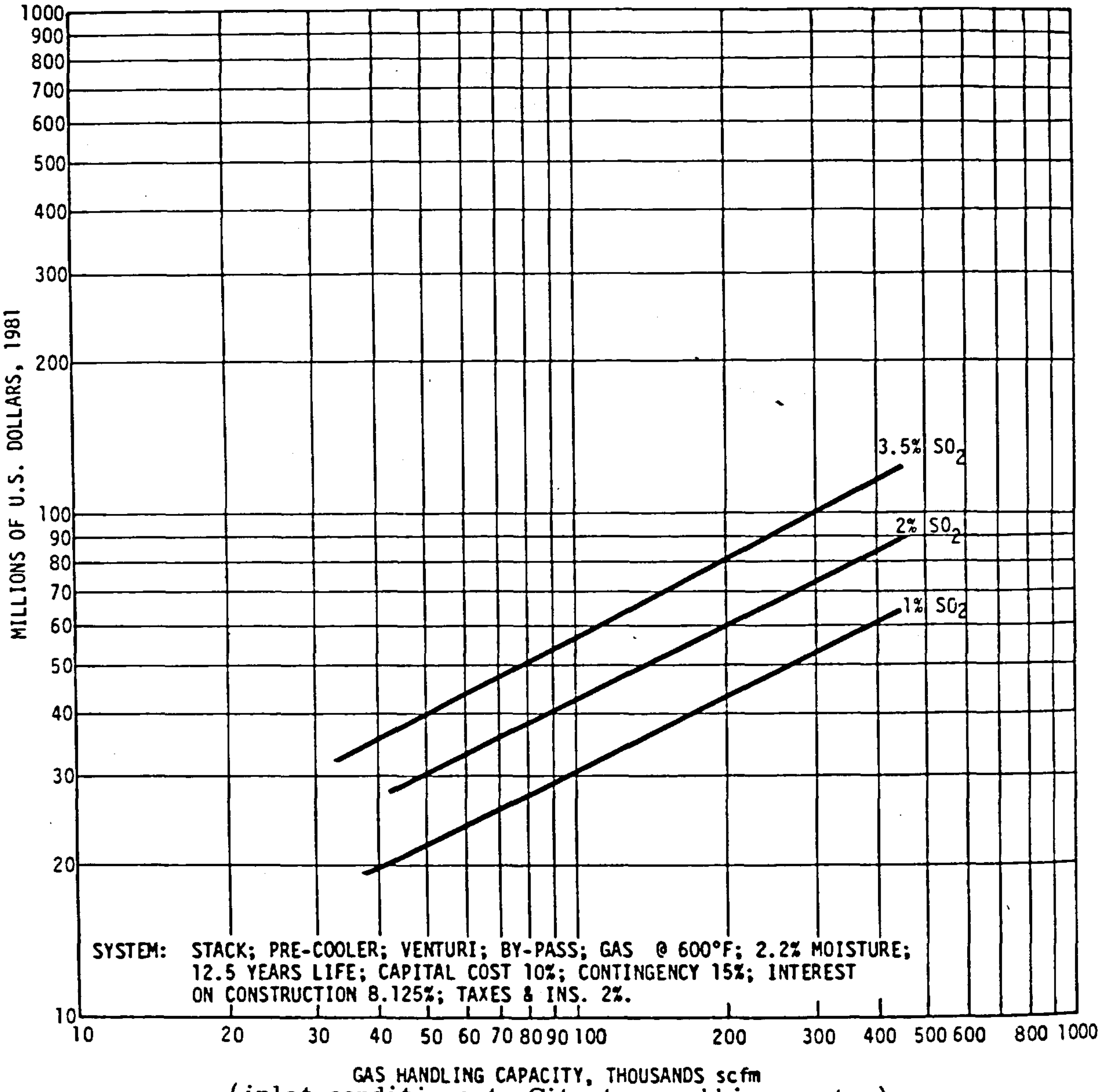
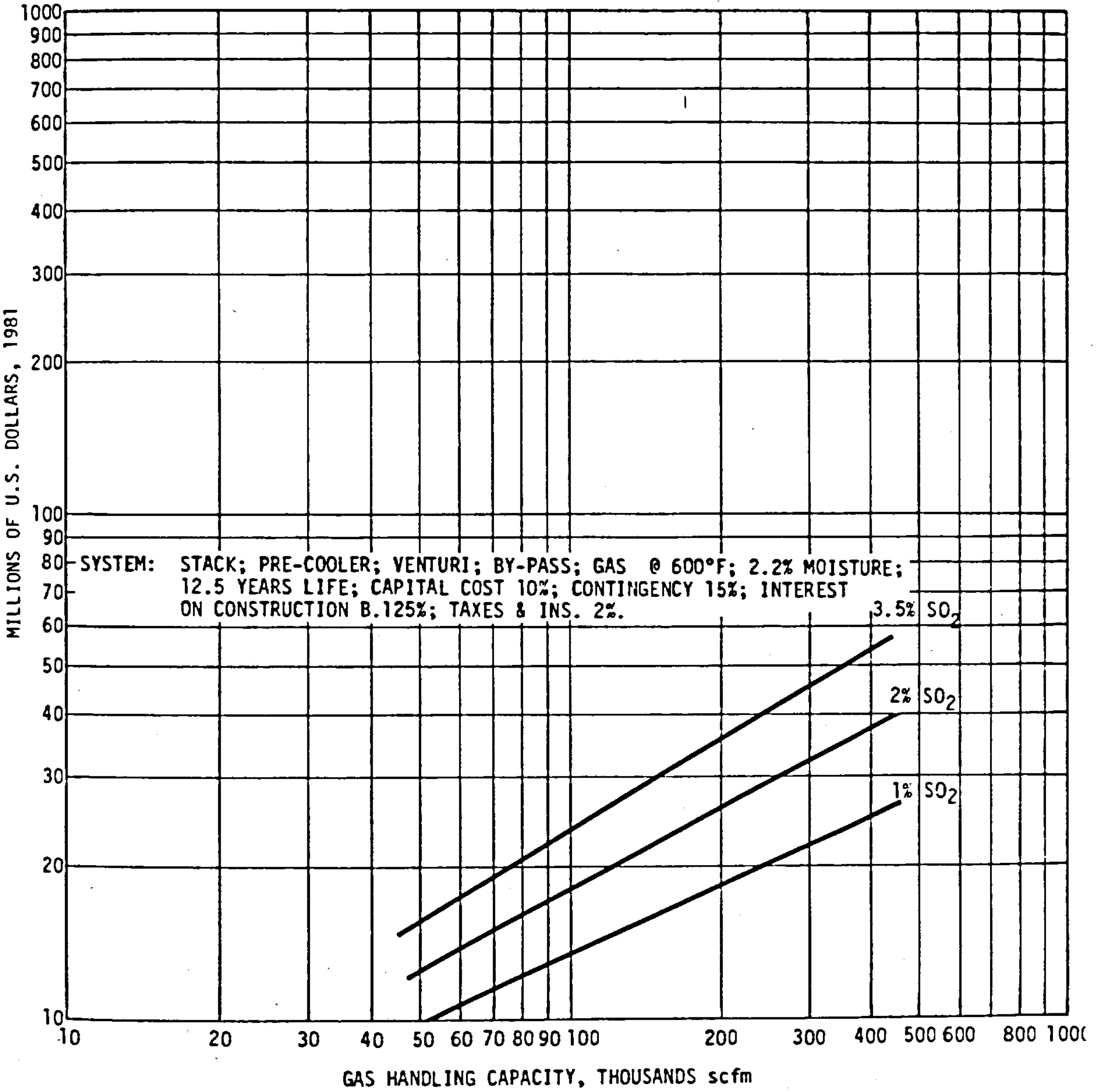


Figure 5.25 Schematic of the citrate liquid SO_2 and storage systems



(inlet conditions to Citrate scrubbing system)

Figure 5.26 Capital cost for a liquid SO_2 plant processing concentrated SO_2 from a Citrate scrubbing system



(inlet conditions to Citrate scrubbing system)

Figure 5.27 Operating cost for a liquid SO_2 plant processing concentrated SO_2 from a Citrate scrubbing system

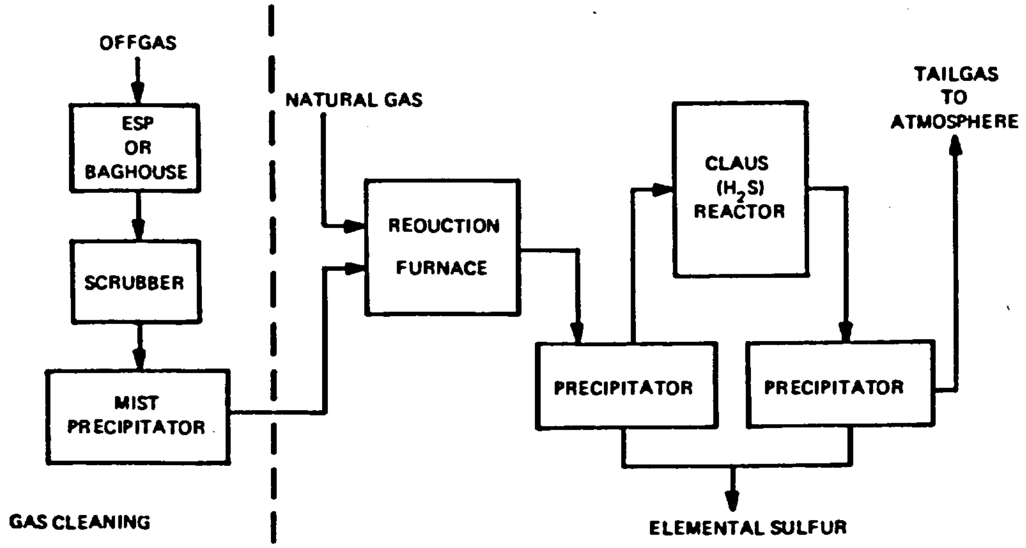


Figure 5.28 Elemental sulfur plant

APPENDIX 6

APPENDIX 6

6. TRENDS IN EMISSIONS (SO_2 AND NO_X)

6.1 FUTURE EMISSIONS IN THE UNITED STATES: DETAILED DISCUSSION BY SECTOR

Projections of emissions baselines for utility and non-utility sectors continued to be updated and have been expanded since publication of the U.S./Canadian interim report in February, 1981. Critical assumptions have changed and the data bases have been improved. In addition, these projections are now presented on a state-by-state basis as well as a national basis. The following section includes a discussion of the methodologies and assumptions behind the state-by-state emission projections in Tables 6.1 through 6.11.

The state-by-state estimates within a sector should be used with caution. Generally, state-by-state numbers are subject to even greater uncertainty than national projections as decisions to shift locations of combustion activity, either individual plants, industries or populations can represent a large percentage change in total emission for a state. Furthermore, the limits to our knowledge of current emission sources which serve as a basis for state level projections, will constrain our projections. These and other uncertainties and constraints are discussed in Section E.

New projections for utility emissions are based upon the new 1980 utility plant data for individual units, and new assumptions about future demand growth. Assumptions concerning coal usage by industrial combustors are of primary importance to SO_2 emission projections; recent estimates of industrial coal use are significantly more conservative than those of early 1981. Recent smelter closings have also caused us to revise emissions from that sector. Emission projections for the Residential/ Commercial, Transportation, and Industrial Process sectors have been updated based on revised energy demand published in the NEPP in July, 1981.

A major difference between this report and the interim report is that no policy scenarios are presented here. We have attempted to refine baseline emission projections, estimating emissions to the year 2000 assuming no change in current regulations. As in the previous report, we conclude that utilities are the dominant source of SO_2 and NO_x, and will remain so for the next 20 years. However, the fastest growing sector in terms of SO_2 is industrial combustion. The South Atlantic and West South Central Regions will experience the greatest growth during the 1980's. Growth in NO_x emissions is more evenly distributed among all regions.

6.1.1 ELECTRIC UTILITIES

The methodology chosen for projecting utility emissions was developed by E.H. Pechan & Associates, and allowed us to take advantage of the new 1980 utility data base developed for the current emission estimates. This set of projections uses the 1980 data base with current plant capacity, capacity utilization, emissions, and planned additions to project future emissions, using assumed rates of growth in electricity demand, assumed retirements and capacity utilization rates, as laid out below. This methodology was chosen because it allowed us to take advantage of the new 1980 data and updated assumptions about future energy use.

This methodology differs substantially from previous methodologies and other ongoing work used to project utility emissions. The previous national projection of utility emissions presented in the Phase I report came from a variety of simulation models which projected utility fuel use, generation by fuel type based on assumptions about fuel and generation costs and growth in overall energy demand. (see Section E) The methodology employed for these projections does not use a simulation or optimization model, and thus, does not project changes in utility operating behavior, plans for new construction or plans to purchase power that would occur because of projected changes in costs of existing and new generation. Rather, the chosen methodology implicity assumes that current economic and non-economic factors will not change dramatically.

Table 6.12 presents emissions and fuel use for the nation, while Tables 6.1 and 6.2 present results on a state-by-state basis. As noted above, state-by-state projections are subject to substantially more uncertainty than more aggregated data. National fuel use by fuel type changes considerably as coal use doubles by 2000, nuclear power is projected to nearly triple and oil and gas use declines by over half. For the nation, both SO_2 and NO_x emissions increase, with NO_x emissions increasing by 50% over 1980 levels by 2000. SO_2 emissions do not increase as dramatically. The increase in SO_2 emissions due to growth by 1990 are almost entirely offset by reductions from compliance with state implementation plan requirements by existing plants. Critical assumptions are discussed below.

Electricity Demand Growth Rates

Electricity demand growth rates were assumed to be 1.5% per year from 1981-1985 and 2.7% per year over the remaining period. These assumed growth rates reflect continuation of the nearly flat generation growth over the past few years, followed after 1985 by a period of increase at annual rates equivalent to DOE mid-range projections from the NEPP. While these assumed rates of generation growth are lower than those used in earlier estimates, significant changes in the structure of the industry are likely to result in lower growth than in the past. One important factor tending to reduce future electricity growth is the high cost of new generating capacity. New capacity is often significantly more costly than existing capacity, though this may vary on a plant-by-plant basis. Each new plant brought on-line tends to increase average electricity costs--increases which tend to reduce future demand. This phenomenon of higher cost for new capacity is the reverse of that which existed from the period near the beginning of the industry through the 1960's; during which time electricity demand growth averaged 7% per year. The large amounts of capital required for new plants, the difficulty the industry has in raising this capital, and the high costs of interest payments have given the industry an incentive to restrain purchases of new power plants and equipment.

These growth rates were assumed to vary slightly by region with higher growth rates in the West, West South Central and Mountain areas and lower than average in the East. The differential regional growth rates were adopted from previous USM model runs (see Section E), which provided state-by-state growth rates based on the Bureau of Economic Analysis Estimates of growth in regional economic activity. These trends are supported by the regional Electric Reliability Councils which project higher rates of demand growth in these regions. Table 13 illustrates projected electricity generation by region. For these projections, current baseload/peakload ratios were maintained in each state.

Plant Life and Capacity Retirements

Plant lifetimes for existing plants were specified by each utility company by unit. No plants currently on-line were allowed to retire before 1991 unless plans were already announced that they were scheduled to do so. For those plants without utility-specified lifetimes, the following lifetimes were assumed:

Coal Steam Plant - 50 years

Oil Steam Plant - 35 years

Gas Steam Plants - 35 years

Nuclear Steam Plants - 35 years.

For coal plants, the above value represents a lengthening of plant life by 5 years over previous analyses. To date, we have little historical data on the expected retirement date for many of the large plants. Most coal-fired capacity (85%) has been added since 1956. As a result, we assume most existing capacity will not be retired until after 2000.

The vintages of coal capacity do vary somewhat by region, with the Northeast and East having a larger percentage of older coal capacity. Thus, this assumption will have a more significant effect in some regions than in others.

Planned Capacity

This analysis specifies all planned additions by unit, based on announced plans by utilities as provided to the Electric Reliability Councils. Nuclear steam capacity by unit was specified by DOE EIA, which provides information by unit including announced on-line dates (see Table 6.14). Scheduled plants were brought on line to meet new demand requirements.

Capacity Factors

The assumed capacity factors are presented in Table 15. All existing plants were maintained at historical capacity factors. Existing oil and gas steam plants however were reduced as listed to reflect gradual scaling back of operations due to high operating costs.

Reconversions of Oil Steam Plants to Coal

Many of the oil steam plants in New England and the Mid Atlantic States were originally designed to burn coal and were later converted to oil. The high operating cost of oil relative to the capital and operating cost of coal conversion has made it economical in many cases to reconvert these plants to coal service. This is constrained, however, by the level of capital expenditure required by the utility to reconvert these plants, and the ability of the utility to raise capital. In the base case, we assume that 15 Gigawatts of such capacity will be converted to coal. This includes 8.4 GW of announced conversion capacity (through 1991) provided by the National Electric Reliability Council, (1) plus additional assumed capacity conversions as listed in Table 6.16.

TABLE 6.16

Additional Assumed Oil Capacity Conversions to Coal
(MW)

New England	1010
Mid Atlantic	1380
South Atlantic	2810
East South Central	140
East North Central	1040
West South Central	170

State and National Fossil Energy Demand

The resulting fossil energy use projections, by state and by region, are presented in Table 6.17.

Emission Rates

For currently operating units, actual emissions were calculated based on the methodology stated in the previous section on current emissions, which includes limits placed on plants by SIP's as average annual limits. Emission rates for all plants built and operating through 1980 are based on actual delivered fuel quantity and quality, together with controls in place. All plants were assumed to comply with SIP limits by 1985. Any proposed SIP changes through 1981 were assumed to be granted.

For new plants, several assumptions must be made about emission standards and fuel type used. New electric power plants can be subject to either of two emission standards, which apply by fuel type, depending on when they commenced construction. The first standard is applicable to plants which began construction between August 17, 1971 and September 18, 1978. The second applies to plants, which commenced construction after September 18, 1978.

Both national NO_x emission standards are listed in Table 6.19. These are uniform standards by fuel type. For the first NSPS, coal and oil-fired plants are subject to a flat maximum limit of 1.2 lbs SO_2 per million Btus for coal plants, and 0.8 lbs for oil units. The new NSPS for coal-fired plants is a sliding scale of 1.2 lbs per million Btus maximum, with at least 90% reduction of SO_2 required to as low as 70% reduction allowed, if emissions are below 0.6 lbs SO_2 per million Btus. All standards are based on 30 day rolling averages.

It is difficult to determine the precise date at which construction commenced, thus, this analysis assumes that plants are subject to a standard based upon the first date of operation. New plants that come on line between 1981 and 1984 are assumed to be subject to the NSPS of 1.2 lbs SO_2 per mm Btus.

Though some states may subject these plants to stricter NSPS limits, no further reductions were required from plants in any states, as it is very difficult to estimate which particular plants will have stricter limits. Furthermore, it was assumed that plants subject to these limits do not represent a significant proportion of the total population.

All new plants scheduled to come on-line after 1983 were assumed to be subject to the new NSPS limit as explained above. All western states (west of North Dakota through Texas) were assumed to scrub SO_2 emissions 90% to meet stricter PSD limits, resulting emission rates of 0.6 lbs SO_2/mm Btus or less, depending on coal type used.

To estimate emissions, it is also necessary to make assumptions about the type and sulfur content of the fuel that will be used. Sulfur content of coal can vary dramatically depending on a variety of factors, including the distribution of the organic and inorganic sulfur content, the way it is mined and the processing which the coal has undergone prior to burning. There is very little good statistical information on the extent of sulfur variability, though we know it can vary substantially, even in the same mine or seam. However, we expect that the average sulfur content of coal purchased will be related to the length of the averaging time of the standard. As the averaging time decreases, the average sulfur content of coal purchased probably decreases to make it less likely that the standard will be violated. This will depend on the variability of the emissions and the degree of confidence required that the limit will not be exceeded. Both NSPS standards require a 30 day rolling average, thus, for this analysis we assume that plants will purchase coal with an average sulfur content 22% below the limit based on assumptions and analyses for previous studies (2). This factor continues to undergo analysis at EPA.

In addition, for the new NSPS we must make assumptions about the type of coal a power plant would burn. In reality, this decision would be based upon the relative delivered costs of various types of coal and capital and operating costs of various scrubbers necessary for the percent removal requirements as well as the sulfur variability as noted above, and the average efficiency of the removal equipment. For this analysis, to capture the economic effect, we assume that coal burned in 1973 was the most economic coal for plants in that area, and it would be scrubbed to the appropriate limits, as reflected in Table 6.18.

Similarly, NO_x emission limits were calculated for new plants subject to 1971 and 1979 NSPS standards, depending on the type of fuel burned. These limits are listed in Table 19. Emission factors used for calculating uncontrolled emissions from existing plants are listed in Table 20. NO_x emissions from most non-NSPS plants are not limited by regulation, with the exception of California. All regulations on NO_x emissions of existing plants have been accounted for.

Table E.1.4 in Section E of the report, presents the results of changes in the values of these assumptions. As expected, changes in SO_2 emissions for all cases for Year 1990 are small, while emissions in Year 2000 are considerably higher for the higher growth case, offset by the higher nuclear growth. The most significant change in SO_2 emissions is found if we assume a shorter lifetime for coal plants (45 years), because existing plants are replaced with new plants with tighter controls. Thus, in 2000, SO_2 emissions drop by 10% from the base case.

Higher growth rates also have a significant effect on NO_x emissions, increasing them substantially as new plants produce higher levels of NO_x. NO_x emission factors are currently undergoing review because of the difficulty in capturing the likely efforts of combustion modification and changes in operating behavior which substantially affect NO_x emissions.

6.1.2 INDUSTRIAL BOILERS AND PROCESS HEATERS

Of the non-utility sectors, industrial combustors contribute the greatest amount of SO_2. Two models developed by ICF, Inc., the Industrial Boiler Model (IBM) and the Process Heat Model (PHM), were used to project SO_2 and NO_x emissions from industrial combustors. The following discussion is derived from references (3) and (4).

The IBM simulates a manufacturer's decision when choosing among different types of fuel prior to construction of a new boiler. The most important model parameters are economic - fuel price, boiler capital cost, operating and maintenance costs; regulatory - NSPS, SIP's, NAP; and technological - physical constraints precluding the use of coal.

The PHM is more of an accounting system than a predictive model, i.e., the process heater population is assumed to remain almost static in terms of types of fuel being used. Economic growth factors are assumed for different industries to reflect increased energy demand, however, greatly increased coal use by process heaters is not anticipated due to technological constraints.

Fuel Prices and Equipment Costs

Following are cost assumptions made by ICF preliminary to forecasting fuel demand:

World Oil Price (1980$ per barrel)

1980	1990	2000
34.0	40.8	47.6

Residual Oil Price at the Refinery (1980$ per MMBtu)

	1980	1990	2000
(Medium Sulfur Content)	5.33	6.23	7.57

Natural Gas Price at the Refinery (1980$ per MMBtu)

1990	2000
5.60	7.36

IBM assumes that on the average, market prices for refined products will be directly coupled to the cost of acquisition and refining of crude oil.

The cost of coal to industry is higher than that for utilities, due to smaller deliveries and the need for sized coal. A CEUM forecast was adjusted to give representative coal prices for industry. ICF calculated delivered fuel prices for each state for the period under analysis.

Tables 6.21, 6.22 and 6.23 include equipment and O & M costs assumed by ICF for the construction of new coal, oil and gas boilers.

Environmental Regulations

Twenty-nine fuel types were available for selection in the IBM. These fuel types are shown in Table 6.26. Some of these were precluded from use due to environmental regulations. Three types of environmental regulations were modeled in IBM:

- A SIP file was developed by EPA in 1980. The file included SO_2 and NO_x emission limits for industrial boilers for each Air Quality Control Region within each state.
- New Source Performance Standards apply to boilers over 250 MMBtu/hr heat input. Coal boilers may emit no greater than 1.2 lb/MMBtu SO_2 and 0.7 lb/MMBtu NO_x. Oil boilers may emit no greater than 0.8 lb/MMBtu SO_2 and 0.3 lb/MMBtu NO_x. Gas-fired boilers are restricted to no greater than 0.2 lb/MMBtu NO_x.
- The IBM assumed that areas currently in non-attainment with SO_2 ambient standards will continue to be in non-attainment throughout the forecast period. In the model, coal-fired boilers larger than 100 MMBtu/hr wishing to locate in those areas are required to use low sulfur coal plus a scrubber.

Characteristics of the Combustor Population

After assumptions regarding fuel and equipment costs and regulatory constraints are made, the next step is to characterize fuel demand in the existing and future boiler population by type of fuel, utilization rate and amount of fuel consumed. For the existing population of boilers the major sources of data are:

- The 1975 Major Fuel Burning Installation File (MFBI) which is based on a 1974 survey of boilers greater than 100 MMBtu/hr input. This file locates boilers in states and is a source for data on boiler age, utilization rate, boiler size, and type of fuel consumed.
- Sales data from the American Boilers Manufacturers Association (ABMA) and the Annual Survey of Manufacturers (ASM) published by the Bureau of Census were used to supplement the MFBI file, providing data on boilers smaller than 100 MMBtu. The ASM is also used to regionalize fuel demand.

Growth in energy demand is distributed across regions with data from the ASM and regional growth projections of the Commerce Department's Bureau of Economic Analysis (BEA) and the Office of Business Economic Research and Statistics (OBERS). These forecasts attempt to predict demographic change, technology substitution, and future industrial activity in regions. Utilization rates and distribution of growth in demand by state are shown in Tables 6.24 and 6.25, respectively.

The IBM models fuel use in the manufacturing sector, specifically including the food, paper, chemical, petroleum refining and primary metals industries. These five industries together consume almost 80 percent of all fuel used in industrial boilers. Remaining fuel use is characterized in an industrial category entitled "other".

Boiler lifetime was assumed to be forty-five years. An additional important assumption was degree of conservation of energy. The IBM assumed that over the period 1980-2000, economic growth would drive fuel use at 2.7 percent compound annual rate for IBM and 2.5 percent for PHM. Assumed conservation slows that pace to 1.9 percent for each category.

In estimating growth demand, i.e., fuel demand by new boilers purchased to satisfy brand-new steam needs, the IBM and PHM assumed dependence on output growth in the manufacturing industries. Industrial growth rates were taken from forecasts of real value published by Wharton Econometric Forecasting Associates, November 1980. The following indicies reflect annual GNP growth of 2.7 percent from 1974 to 1982 and 3.0 percent between 1983 and 2000.

Cumulative Industrial Growth in the IBM

Industry	1974	1990	2000
Food	1.000	1.559	1.923
Paper	1.000	1.479	1.910
Chemicals	1.000	1.778	2.329
Pet. Refining	1.000	1.143	1.306
Primary Metals	1.000	1.175	1.557
Other	1.000	1.612	2.171

Cumulative Industrial Growth in the PHM

Industry	1974	1990	2000
Paper	1.000	1.474	1.910
Chemicals	1.000	1.778	2.329
Petroleum	1.000	1.143	1.309
Stone, Clay, Glass	1.000	1.568	2.097
Primary Metals	1.000	1.175	1.557
Other	1.000	1.612	2.171

The same sources used in the IBM to characterize and distribute energy demand are used for the PHM. However, two important differences between the two models are:

1) In the IBM fuel choice decisions are made on the basis of a detailed comparison of the cost for each alternative. However, for process heaters, technical constraints, particularly with regard to flame characteristics, limit fuel choice. Solid coal use is precluded in many industrial processes, with

the exception of kilns in the cement and lime industries where coal use is expected to increase significantly. Therefore, PHM assumes that process heater fuel use will follow much the same patterns as in the 1974 base year.

2) Unlike boilers, process heater emissions are not directly regulated unit-by-unit. The baseline projection therefore, does not put a constraint on the use of any specific fuel or require the use of any pollution control devices designed to control fuel based emissions.

Industrial Energy Demand

Finally, assumptions described above concerning the existing and future combustor population enable the IBM and PHM to project fuel demand. The results for the U.S. as a whole are included in the following tables:

	Projection (10^{15} Btu)	
	1990	2000
Total Industrial Energy Demand	16.2	18.7
Industrial Boiler Energy Demand	6.2	7.2
Process Heater Energy Demand	10.0	11.5
Boiler Energy Demand by Fuel Type		
Coal	2.3	5.7
Oil	0.0	0.4
Gas	3.9	1.1
By-products	0.0	0.0
Process Heater Energy Demand by Fuel type		
Coal	0.6	0.7
Oil	1.5	1.7
Gas	4.7	5.5
By-products	3.2	3.6

New boilers purchased to meet expanded steam needs are a major source of expanded coal use. The ICF study assumed that coal would capture over 90 percent of the market share for fossil fuel boilers purchased for this reason. However, accelerated replacements are equally important. These are replacements for economic reasons, i.e., when it is cheaper to build a new coal unit that continues to operate an existing oil or gas facility. By the year 2000, 47 percent of total coal use is the result of accelerated replacements. Further, all retirements were assumed to be due to economics and not to boiler age.

Fuel Sulfur Content and Emission Factors

With a few exceptions, emission factors included in EPA's AP-42 publication, "Compilation of Air Pollutant Emission Factors," July 1979, are used together with assumptions concerning the sulfur contents of various coal types and residual oils, to calculate SO_2 and NO_x emissions. The emission factors in the IBM and PHM are listed in Tables 6.26, 6.27, 6.28, and 6.29.

Average sulfur contents of fuels in the IBM and PHM are assumed to be:

Fuel	Average Percent Sulfur
High Sulfur Coal	2.5%
Medium Sulfur Coal	1.2%
Low Sulfur Coal	0.6%
High Sulfur Oil	1.9%
Medium Sulfur Oil	0.8%
Low Sulfur Oil	0.4%

After specifying the industry, location of combustor, size, and annual utilization rate, the models make an investment or operating decision concerning fuel choice. In the IBM, the lowest cost alternative is always chosen. Once the fuel characteristics of an existing and future combustor population are determined, fuel sulfur contents are estimated and emission factors are used to calculate the projected emissions in Tables 6.3 and 6.4 of this Appendix.

6.1.3 PRIMARY NON-FERROUS SMELTERS

In 1970, approximately 97 percent of total uncontrolled sulfur oxide emissions attributed to non-ferrous smelting was released by smelters west of the Mississippi River. Los Alamos Scientific Laboratory projected SO_2 emissions anticipated from western smelters in 1990 and 2000 based on a site-by-site survey and considerations of federal and state regulations, and technologic and economic factors. Assumptions concerning future production capacity and sulfur contents of ore were essential for the emission calculations. The following discussion is taken from the report, "Sulfur Dioxide Emissions from Primary Non-ferrous Smelters in the Western United States," Mangeng and Mead, August 1980.

Economic Factors

Copper

Since 1975, there has been a lack of announced capital expenditures or plans to expand smelting capacity. Considering this trend and environmental difficulties associated with reverberatory furnaces, the study made pessimistic estimates of future smelting capacity and production. Five analyses of the future of copper smelting were referenced (6,7,8,9,10).

In 1990, western copper smelters are assumed to be producing 1 562 000 metric tons of copper. Copper production in 2000 is assumed to be 1 782 000 metric tons.

Lead

Projections concerning lead production rely on growth projections published by the U.S. Bureau of Mines ("Lead," Ryan and Hague, U.S. Dept. of Interior report MCP-9, December 1977). Primary demand for lead is assumed to increase by approximately 2 percent per year with domestic mines supplying 68 percent of the demand. By 2000, domestic mine production will be approximately 25 percent above existing smelter capacity. There will be less foreign concentrates imported for smelting as domestic mine production increases. Eventually, additional smelting capacity or increased imports of lead bullion will be required to meet the projected demand. This projection assumed that projected demand will be met half by metal imports and half by domestic smelting capacity expansion. Because 85 percent of domestic mine production is in Missouri, it is reasonable to assume that any additional smelting capacity will be located there. Lead production in 1990 is projected to be 607 000 tonnes; in 2000, lead production is assumed to be 755 500 tonnes.

Zinc

The Bureau of Mines was also referenced for the forecast of zinc production ("Zinc," Cammarata, U.S. DOI report MCP-12, May 1978). Demand was estimated to increase 3 percent per year. In recent years, domestic mine production has met 36 percent of the primary demand for lead. In 1995, domestic mine production is projected to equal current smelter capacity. Approximately two-thirds of domestic zinc smelting capacity is located in the eastern U.S. (Only about 4 percent of smelter SO_2 in the West comes from zinc smelters.) The Los Alamos study assumed that any increase in smelting capacity will occur at these smelters rather than in the three located in the West. The amount of zinc smelted in the West is assumed to be one-third of the projected primary mine production. Western zinc production in 1990 is assumed to be 140 000 tonnes; in 2000 production is assumed to be 164 000 tonnes.

Regulatory Factors

Any new primary non-ferrous smelters coming on-line must comply with stringent NSPS which allow no greater than 0.065 percent SO_2 by volume in the smelter offgases. Modified or reconstructed sources whose emissions would exceed those of the old source must also comply with NSPS. In addition, each state was required by the 1977 Clean Air Act Amendments to develop SIP's which reduce overall atmospheric pollution loading on a continuous basis; dispersion techniques such as supplementary control systems cannot be substituted for continuous emission reduction technology to achieve National Ambient Air Quality Standards (NAAQS). By 1988, all non-ferrous smelters must be in compliance with SIP's, which require approximately a 90 percent reduction in SO_2 emissions from uncontrolled levels.

Each non-ferrous smelter in the western U.S. was examined in detail. It was observed that western zinc smelters are achieving high levels of SO_2 control at the two electrolytic plants operating in the west. The four lead smelters in this study have either achieved required levels of control or will reduce emissions to allowed levels by the mid 1980's. Examination of baseline year emissions reveals that approximately 85 percent of total SO_2 emissions from primary non-ferrous smelters in the western U.S. was produced by copper smelters.

Table 6.5 presents SO_2 emissions from non-ferrous smelters by state for 1990 and 2000. NO_x emissions from smelters are negligible and no attempt was made to quantify NO_x from smelters. Since the report was published, three smelters have been closed: Anaconda Copper at Anaconda, Montana; Bunker Hill Lead at Bradley, Idaho; and Bunker Hill Zinc at Kellogg, Idaho. Capacities and emission have been subtracted from the projections accordingly. The report further predicts the closing of three copper smelters before 1990. These are ASARCo at Tacoma, Washington; Kennecott at McGill, Nevada; and Phelps Dodge at Douglas, Arizona.

The projections assume that technological improvements will be developed and introduced at smelters and that levels of control presently required by SIP's will be installed by 1990. No new smelters are assumed in the projection period; although some expansion of existing capacity is assumed to take place. Emissions have been calculated with assumed sulfur contents of ore and assumed production capacities. These are shown in Table 6.30. Uncertainties regarding this analysis are discussed in Section E.

6.1.4 RESIDENTIAL/COMMERCIAL

Tables 6.6 and 6.7 are projections of SO_2 and NO_x emissions from the residential/commercial sector. The U.S. Department of Energy used the SEAS model developed by the Mitre Corporation to project emissions from these sectors. The projections assumed energy demand by type of fuel as published in the report, "Energy Projections to the Year 2000," July 1981, which is a supplement to the NEPP. Energy values from the mid-range case were used for the model runs.

The SEAS model is basically an accounting system which accepts energy demand as input and performs an emission calculation using emission factors for different types of fuel (fossil fuels, solar, wood) published by EPA in AP-42. Regional disaggregation is accomplished by using Bureau of Economic Analysis data concerning population characteristics in residences and commercial buildings. Growth factors regarding the residential/commercial sector are then applied to project future emissions.

The NEPP makes assumptions regarding fuel prices, population growth, and degree of energy conservation, to project fuel consumption. Following are tables of major assumptions concerning the residential/commercial sectors.

Delivered Fuel Prices (1980 $ per MMBtu)

Residential	1980	1990	2000
Distillate	7.04	10.74	14.01
Liquified Gas	6.08	9.39	12.20
Natural Gas	3.83	8.00	9.55
Electricity	15.70	18.10	20.74
Commercial	**1980**	**1990**	**2000**
Distillate	6.31	9.92	13.00
Residual Oil	4.29	8.03	10.68
Liquified Gas	5.91	9.35	12.28
Natural Gas	3.13	7.72	9.28
Electricity	16.06	19.01	22.02

	Populations (millions)	Households (millions)	Commercial Floor Space (billions of sq. Ft)
1980	227	80	32
1990	249	96	41
2000	266	108	52

	Energy Use Per Household (MMBtu/hr)	Energy Use Per Commercial Sq. Ft. (MMBtu/yr)
1980	134	0.228
1990	110	0.190
2000	96	0.163

Residential fuel uses are primarily for space heating and air conditioning. Other uses include water heating, refrigeration, freezing, cooking and lighting. Commercial fuel uses include, besides space conditioning, water heating, lighting, and production of asphalt.

Space conditioning shows the greatest promise for future reductions of fuel use through conservation. Total energy use per household and commercial square foot are projected to decline by 33 percent by the year 2000. By 1990, conservation will be 20 percent. This analysis assumes that energy savings in space conditioning will be realized in three ways:

- improvement of the thermal envelope of the structures;
- improvement of thermal efficiency of the equipment;
- alteration of space conditioning usage patterns, i.e., changing thermostat settings, lowering ventilation rates, and computerizing zone controls.

Changing fuel use patterns are generally influenced by prices. Prior to 1984, incremental pricing regulations are assumed to hold the price of natural gas below its true market value, and thus encourage its continued use in the residential/ commercial sectors. After 1985, with price regulations removed, the market price of natural gas is expected to be substantially higher, therefore, dampening its market penetration in new space heating equipment.

The increased use of electricity and renewable resources is primarily responsible for undercutting oil's market share in residential and commercial space heating. In the 1990 to 2000 time period, electricity is assumed to penetrate about 32 percent of the space conditioning equipment market.

Direct use of renewable fuels, such as wood, accounts for more than 10 percent of the new residential and commercial space heating equipment in the 1990 to 2000 period. Table 6.31 includes the breakdown of residential and commercial fuel use by fuel type for the projected period.

6.1.5 INDUSTRIAL PROCESSES

The industrial process sector includes industrial uses for fuel other than providing heat for steam or for a manufacturing process. An example of such a process is municipal sewage/ waste disposal, where fuel is burned to dispose of waste, not to manufacture a product. SO_2 and NO_x emissions from this sector are also due to fugitive losses such as SO_2 emissions from sulfur removal processes at a petroleum refinery. This type of fugitive loss is due to a chemical process and is not related to combustion.

As for the Residential/Commercial sector, the SEAS model establishes base year characteristics of the industrial process sector. The following industries are included:

- Pulp/Paper
- Inorganic Chemical
- Organic Chemical
- Stone and Clay Products
- Iron and Steel
- Fertilizer
- Fiberglass
- Coal Mining
- Gas Processing/Distribution/Extraction
- Oil Distribution/Extraction
- Petroleum Refining
- Nuclear Processing/Distribution
- Municipal Sewage/Waste

The 1972 Census of Manufacturers and other data from the Department of Commerce were used to determine base year fuel use and industrial activity. Data from the OBERS and BEA are used to forecast changes in industrial activity over the period 1980 to 2000. To calculate emissions, AP-42 emission factors are applied to the various process categories.

Following is a listing of industries, their assumed growth rate between 1975 and 2000, and the regions assumed to experience new growth (5).

Steel Production is assumed to grow by over 70 percent between 1975 and 2000. The Mid Atlantic and East North Central States accounted for more than 75 percent of U.S. iron and steel production in 1975. In 2000, these states are assumed to produce almost 70 percent of the nation's iron and steel. Pennsylvania is clearly the leader, followed by Illinois, Indiana and Ohio.

Stone and Clay Products will more than double between 1975 and 2000. This increase is caused largely by increased demand for cement, concrete, gypsum, asbestos, crushed stone, clay and gravel. As a rule, construction materials are produced locally to meet local demand. Consequently, regional variations in construction material production tend to follow regional population change.

Pulp and Paper includes the manufacture of pulp from wood and other cellulose fibers and rags; the manufacture of paper and paperboard; and the manufacture of paper and paperboard into converted products. National production by the pulp and paper industry is forecast to more than double from 1975 through 2000. The Southeastern and East North Central States produced 50 percent of the paper and paperboard in the U.S. in 1975. These regions are forecast to more than triple their total production of paper. Remaining paper production is spread evenly through New England, the Mid Atlantic, West South Central and Western States.

The Chemical Industry is forecast to grow very rapidly from 1975 to 2000. Industrial chemicals, its largest component, is forecast to grow by a factor of four over the forecast period. Many chemical plants are located near the major petroleum refining regions along the Middle Atlantic, Gulf and West Coast areas of the U.S. In addition to these chemical production centers, there are many chemical plants located in the industrialized portions of the Ohio River Valley. Overall, chemical plants tend to be located near major manufacturing centers.

6.1.6 TRANSPORTATION

The Transportation SO_2 and NO_x emission projections in Tables 6.10 and 6.11 are derived from two different models. Transportation SO_2 projections come from the SEAS model of the Mitre Corp.; Transportation NO_x results from the MOBILE2 Model developed by EPA.

Both SEAS and MOBILE2 model the following mobile source categories:

- Light Duty Vehicles (LDV)
  - gasoline and diesel powered passenger cars
- Light Duty Trucks (LDT)
- Heavy Duty Diesels (HDD)
- Heavy Duty Gasoline (HDG)
- Off-Highway Vehicles
  - farm equipment
  - motorcycles
  - rail
  - aircraft
  - vessels (inland waterways and barges)

SEAS starts with a 1975 historical base year, characterizing VMT through inter-city travel data for LDV, LDT and buses. All other mobile source categories are regionalized by using population statistics. SEAS assumes the following transportation statistics as given in the NEPP to project growth in the Transportation sector:

Energy Consumption (10^{15} Btu)

	1980	1990	2000
Transportation	18.6	17.6	18.4

Fuel Prices (1980 $ per MMBtu)

	1980	1990	2000
Gasoline	9.76	13.35	16.47
Distillate	6.29	10.98	14.37
Residual	4.29	7.76	10.30
Jet Fuel	6.64	10.50	14.04

Consumption by type of Fuel (10^{15} Btu)

	1980	1990	2000
Oil	18.0	16.7	17.2
Natural Gas	0.6	0.7	0.8
Alcohol	----	0.2	0.4
Total	18.6	17.6	18.4

To calculate SO_2 emissions, SEAS applies emission factors developed in the MOBILE1 program and assumes a trace level of sulfur in gasoline of 0.044 percent.

For the NO_x projections, EPA also started with a historical base year. The base year statistics come from the 1977 NEDS, maintained by EPA.

MOBILE2 adds percentage growth each year to account for growth in VMT. The following growth factors were assumed:

Percent Growth Per year in VMTs	LDV	LDT	HDG	HDD	Off Highway
	+1.4	+4.6	-2.0	+5.0	+2.5

MOBILE2 then applies emission factors to each highway vehicle class. The projected composite emission factors for the entire fleet of vehicles follows:

Composite Emission Factors (g/mi)

Vehicle Current Standard		1979	1990	1995
LDV	1 g/mi	3.01	1.53	1.37
LDT	2.3 g/mi	3.75	2.05	1.92
HDG	10.7 g/b.hp.hr.	10.02	11.48	11.80
HDD	10.7 g/b.hp.hr.	25.59	25.59	25.59

Each model year is treated differently in the program, with each year having unique emission factors and deterioration rates to reflect vehicle population, mode of travel and use.

Since MOBILE2 only projects emission on a national scale, state fractions developed by the Mitre Corp. were used to distribute total NO_x among the states.

REFERENCES

(1) National Electric Reliability Council, "Electric Power Supply and Demand, 1981-1990", July, 1981.

(2) TRI, "Electric Utility Emissions: Control Strategies and Costs", Draft Report, April, 1981. A similar factor (2) was recently used by EPA in an analysis of alternative utility NSPS standards by ICF, Inc., October 1981.

(3) "Coal Use by Industry: A Forecast and Sensitivity Analysis". 1982 U.S. Department of Energy.

(4) "Air Pollution Emissions from the Manufacturing Sector". 1981 U.S. Environmental Protection Agency.

(5) "Scenario Reference Manual for the Residuals Accounting Model," McBrien and Jones, The Mitre Corp. September 1981.

(6) "Copper," Schroeder, U.S. Department of the Interior Report MCP-3, June 1977.

(7) "The Potential Economic Impact of U.S. Regulations on the U.S. Copper Industry", Staff Study, Industry and Trade Administration, U.S. Department of Commerce, April 1979.

(8) "Economic Impact of Environmental Regulations on the United States Copper Industry", Arthur D. Little, Inc., January 1978.

(9) "Materials Interchangeability Development and Supplies, Phase I, Model of the Copper Industry from Mine to Conductor Wire", U.S. Bureau of Mines, January 1978.

(10) "Commodity Supply Restrictions Study, Policy Implications of Producer Country Supply Restrictions: The World Copper Market", Charles River Associates, NTIS report PB-264, August 1976.

TABLE 6.1

Sector: Electric Utility
Projected SO_2 Emissions: (10^3 metric tons)

	1990	2000
New England		
Connecticut	24	27
Maine	4	6
Massachusetts	101	103
New Hampshire	63	60
Rhode Island	4	3
Vermont	2	3
Regional Total	198	202
Mid Atlantic		
New York	426	343
New Jersey	95	132
Pennsylvania	1 270	1 193
Regional Total	1 791	1 668
South Atlantic		
Delaware	33	26
Dist. of Columbia	4	4
Florida	673	746
Georgia	714	711
Maryland	228	273
North Carolina	411	451
South Carolina	249	259
Virginia	145	128
West Virginia	888	942
Regional Total	3 345	3 540
East South Central		
Alabama	489	503
Kentucky	661	683
Mississippi	131	130
Tennessee	888	704
Regional Total	2 169	2 020
Pacific		
California	64	64
Oregon	3	21
Washington	65	81
Regional Total	132	166
East North Central		
Illinois	1 139	1 176
Indiana	1 247	1 254
Michigan	561	626
Ohio	1 905	1 892
Wisconsin	737	686
Regional Total	5 589	5 634
West South Central		
Arkansas	52	84
Louisiana	95	157
Oklahoma	73	75
Texas	409	487
Regional Total	629	803
West North Central		
Iowa	222	243
Kansas	140	155
Minnesota	162	186
Missouri	1 070	1 086
Nebraska	62	69
North Dakota	98	128
South Dakota	25	26
Regional Total	1 779	1 893
Mountain		
Arizona	90	88
Colorado	100	103
Idaho	4	10
Montana	19	23
Nevada	49	51
New Mexico	79	88
Utah	43	44
Wyoming	88	96
Regional Total	472	503
Total 48 States	16 104	16 430

Source: E.H. Pechan & Associates, Inc. "Baseline Projections of Sulfur and Nitrogen Oxides from the Electric Utility Industry", for EPA, Office of Research & Development.

Note: Numbers may not exactly add due to rounding.

TABLE 6.2

Sector: Electric Utility
Projected NO_x Emissions: (10^3 metric tons)

	1990	2000
New England		
Connecticut	20	32
Maine	3	7
Massachusetts	55	83
New Hampshire	25	25
Rhode Island	3	4
Vermont	2	4
Regional Total	108	155
Mid Atlantic		
New York	161	171
New Jersey	96	137
Pennsylvania	372	369
Regional Total	629	677
South Atlantic		
Delaware	21	26
Dist. of Columbia	2	4
Florida	273	407
Georgia	209	238
Maryland	71	103
North Carolina	211	300
South Carolina	106	117
Virginia	68	70
West Virginia	313	394
Regional Total	1 274	1 659
East South Central		
Alabama	172	224
Kentucky	282	324
Mississippi	52	48
Tennessee	184	180
Regional Total	690	776
Pacific		
California	117	140
Oregon	5	39
Washington	23	118
Regional Total	145	297

	1990	2000
East North Central		
Illinois	447	510
Indiana	380	418
Michigan	260	348
Ohio	499	671
Wisconsin	249	262
Regional Total	1 835	2 209
West South Central		
Arkansas	42	84
Louisiana	113	178
Oklahoma	159	236
Texas	621	898
Regional Total	935	1 396
West North Central		
Iowa	108	133
Kansas	103	114
Minnesota	107	147
Missouri	233	255
Nebraska	47	57
North Dakota	62	87
South Dakota	20	27
Regional Total	680	820
Mountain		
Arizona	92	132
Colorado	104	140
Idaho	6	18
Montana	29	49
Nevada	52	69
New Mexico	96	137
Utah	50	75
Wyoming	109	131
Regional Total	538	751
Total 48 States	6 834	8 740

Source: E.H. Pechan & Associates, Inc. "Baseline Projections of Sulfur and Nitrogen Oxides from the Electric Utility Industry", for EPA, Office of Research & Development.

Note: Numbers may not exactly add due to rounding.

TABLE 6.3

Sector: Industrial Boilers and Process Heaters
Projected SO_2 Emissions: (10^3 metric tons)

	1990	2000
New England		
Connecticut	24.5	57.0
Maine	41.2	65.1
Massachusetts	33.2	65.1
New Hampshire	12.6	16.3
Rhode Island	5.3	8.2
Vermont	3.4	0
Regional Total	120.2	211.6
Mid Atlantic		
New York	150.6	239.0
New Jersey	100.7	213.9
Pennsylvania	316.4	471.8
Regional Total	567.7	924.7
South Atlantic		
Delaware	8.3	21.5
Dist. of Columbia*	-	-
Florida	83.2	185.5
Georgia	103.6	235.5
Maryland	41.0	78.5
North Carolina	89.8	157.0
South Carolina	76.5	164.2
Virginia	84.8	142.7
West Virginia	82.0	142.7
Regional Total	569.2	1 127.7
East South Central		
Alabama	127.9	223.0
Kentucky	36.2	65.5
Mississippi	43.2	78.7
Tennessee	132.7	242.6
Regional Total	340.0	609.9
Pacific		
California	58.7	137.6
Oregon	24.1	44.1
Washington	52.3	82.5
Regional Total	135.1	264.3

	1990	2000
East North Central		
Illinois	200.1	367.3
Indiana	178.3	142.5
Michigan	176.8	314.8
Ohio	291.9	411.0
Wisconsin	164.7	271.1
Regional Total	1 011.8	1 506.7
West South Central		
Arkansas	44.9	118.5
Louisiana	175.8	468.3
Oklahoma	3.7	10.7
Texas	228.9	796.6
Regional Total	453.4	1 394.1
West North Central		
Iowa	65.1	129.3
Kansas	55.0	98.8
Minnesota	43.6	76.0
Missouri	36.0	76.0
Nebraska	14.5	22.8
North Dakota	1.9	0
South Dakota	1.9	0
Regional Total	218.1	402.9
Mountain		
Arizona	12.7	21.8
Colorado	30.3	54.6
Idaho	11.7	21.8
Montana	4.9	10.9
Nevada	1.9	0
New Mexico	1.9	0
Utah	18.5	21.8
Wyoming	4.9	0
Regional Total	86.9	131.0
Total U.S.	3 502.4	6 573.0

Source: "Coal Use by Industry: A Forecast and Sensitivity Analysis." ICF, Inc., 1982. U.S. Department of Energy.

"Air Pollution Emissions from the Manufacturing Sector." ICF, Inc., 1981. U.S. Environmental Protection Agency.

* District of Columbia emissions are included in Maryland emissions.

TABLE 6.4

Sector: Industrial Boilers and Process Heaters
Projected NO_x Emissions: (10^3 metric tons)

	1990	2000
New England		
Connecticut	27.1	34.1
Maine	33.4	42.0
Massachusetts	34.3	43.1
New Hampshire	9.9	12.5
Rhode Island	5.5	6.8
Vermont	3.6	4.5
Regional Total	113.7	143.0
Mid Atlantic		
New York	95.1	123.5
New Jersey	86.9	112.9
Pennsylvania	206.6	268.5
Regional Total	388.6	504.9
South Atlantic		
Delaware	9.8	12.9
Dist. of Columbia*	-	-
Florida	64.5	84.8
Georgia	74.4	97.9
Maryland	41.2	54.2
North Carolina	59.1	77.8
South Carolina	50.2	66.1
Virginia	66.3	87.3
West Virginia	70.7	93.1
	436.2	574.1
East South Central		
Alabama	88.6	116.5
Kentucky	42.1	55.4
Mississippi	36.0	47.4
Tennessee	86.0	113.1
Regional Total	252.7	332.4
Pacific		
California	132.6	175.2
Oregon	28.8	38.1
Washington	54.4	71.8
Regional Total	215.8	285.1

	1990	2000
East North Central		
Illinois	166.0	208.6
Indiana	106.5	133.8
Michigan	124.9	157.0
Ohio	237.2	298.2
Wisconsin	79.6	100.1
Regional Total	714.2	897.7
West South Central		
Arkansas	47.4	63.3
Louisiana	195.2	260.7
Oklahoma	21.6	28.9
Texas	417.0	557.1
Regional Total	681.2	910.0
West North Central		
Iowa	29.8	40.8
Kansas	35.4	48.5
Minnesota	50.3	68.8
Missouri	31.6	43.4
Nebraska	19.3	12.7
North Dakota	1.8	2.5
South Dakota	1.8	2.5
Regional Total	160.0	219.1
Mountain		
Arizona	25.3	31.8
Colorado	16.0	20.1
Idaho	8.5	10.6
Montana	5.1	6.4
Nevada	2.5	3.2
New Mexico	2.5	3.2
Utah	14.3	17.9
Wyoming	6.7	8.5
Regional Total	80.9	101.6
Total U.S.	3 043.3	3 967.9

Source: "Coal Use by Industry: A Forecast and Sensitivity Analysis." ICF, Inc., 1982. U.S. Department of Energy.

"Air Pollution Emissions from the Manufacturing Sector." ICF, Inc., 1981. U.S. Environmental Protection Agency.

* District of Columbia emissions are included in Maryland emissions.

Table 6.5

Sector: Primary Nonferrous Smelters
Projected SO_2 Emissions: (10^3 metric tons)

	1990	2000
New England		
Connecticut	-	-
Maine	-	-
Massachusetts	-	-
New Hampshire	-	-
Rhode Island	-	-
Vermont	-	-
Regional Total	-	-
Mid Atlantic		
New York	-	-
New Jersey	-	-
Pennsylvania	-	-
Regional Total	-	-
South Atlantic		
Delaware	-	-
Dist. of Columbia	-	-
Florida	-	-
Georgia	-	-
Maryland	-	-
North Carolina	-	-
South Carolina	-	-
Virginia	-	-
W. Virginia	-	-
Regional Total	-	-
East South Central		
Alabama	-	-
Kentucky	-	-
Mississippi	-	-
Tennessee	-	-
Regional Total	-	-
Pacific		
California	-	-
Oregon	-	-
Washington	-	-
Regional Total	-	-
East North Central		
Illinois	-	-
Indiana	-	-
Michigan*	-	-
Ohio	-	-
Wisconsin	-	-
Regional Total	-	-
West South Central		
Arkansas	-	-
Louisiana	-	-
Oklahoma	7.0	7.0
Texas	40.0	42.0
Regional Total	47.0	49.0
West North Central		
Iowa	-	-
Kansas	-	-
Minnesota	-	-
Missouri	21.4	28.0
Nebraska	-	-
North Dakota	-	-
South Dakota	-	-
Regional Total	21.4	28.0
Mountain		
Arizona	376.0	279.0
Colorado	-	-
Idaho	-	-
Montana	4.0	4.5
Nevada	-	-
New Mexico	89.0	93.0
Utah	51.0	60.0
Wyoming	-	-
Regional Total	520.0	436.5
Total U. S.	588.4	513.5

Source: "Sulfur Dioxide Emissions From Primary Non-ferrous Smelters in the Western United States." C. Mangeng, R. Mead. Los Alamos Scientific Laboratory. August, 1980.

*This study did not include the Copper Range White Pine, Michigan smelter whose current emission rate is 41,411 metric tons per year. This smelter is currently in compliance with applicable regulations.

Table 6.6

Sector: Residential/Commercial*
Projected SO_2 Emissions: (10^3 metric tons)

	1990	2000
New England		
Connecticut	7.6	4.9
Maine	11.2	7.4
Massachusetts	75.5	48.8
New Hampshire	7.2	4.6
Rhode Island	8.5	5.5
Vermont	7.2	4.8
Regional Total	117.2	76.0
Mid Atlantic		
New York	142.7	98.5
New Jersey	22.4	52.8
Pennsylvania	118.5	105.9
Regional Total	283.6	257.2
South Atlantic		
Delaware	6.6	5.8
Dist. of Columbia	11.7	9.5
Florida	15.0	12.5
Georgia	12.3	9.9
Maryland	42.1	37.7
North Carolina	21.3	18.1
South Carolina	9.1	8.5
Virginia	55.2	52.5
West Virginia	11.5	11.5
Regional Total	184.8	165.8
East South Central		
Alabama	6.5	5.0
Kentucky	10.9	9.9
Mississippi	6.2	10.6
Tennessee	13.6	12.4
Regional Total	37.3	37.9
Pacific		
California	55.6	53.9
Oregon	14.9	13.2
Washington	18.1	15.7
Regional Total	88.6	82.8

	1900	2000
East North Central		
Illinois	38.9	28.4
Indiana	26.5	20.8
Michigan	10.9	18.5
Ohio	25.3	21.2
Wisconsin	18.6	14.5
Regional Total	120.3	103.4
West South Central		
Arkansas	6.1	4.1
Louisiana	3.9	2.8
Oklahoma	7.3	4.8
Texas	27.5	18.7
Regional Total	44.7	30.5
West North Central		
Iowa	6.3	4.5
Kansas	2.4	1.5
Minnesota	14.2	10.3
Missouri	10.0	7.0
Nebraska	2.7	1.8
North Dakota	4.8	4.3
South Dakota	3.6	3.0
Regional Total	44.0	32.4
Mountain		
Arizona	11.9	11.6
Colorado	33.7	32.4
Idaho	9.3	8.6
Montana	4.5	3.9
Nevada	3.8	3.6
New Mexico	1.8	1.3
Utah	14.5	13.5
Wyoming	9.1	8.3
Regional Total	88.6	83.2
Total U.S.	1 009.2	869.1

Source: SEAS Program. June, 1981. The Mitre Corp./U.S. Department of Energy.

*The Residential/Commercial sector includes the consumption of fossil fuels, solar energy, and wood.

Table 6.7

Sector: Residential/Commercial*
Projected NO_x Emissions: (10^3 metric tons)

	1900	2000
New England		
Connecticut	7.3	6.3
Maine	7.6	4.8
Massachusetts	44.5	31.8
New Hampshire	4.7	3.6
Rhode Island	5.2	3.8
Vermont	3.6	2.6
Regional Total	72.9	53.0
Mid Atlantic		
New York	83.1	61.2
New Jersey	36.9	27.9
Pennsylvania	46.6	40.1
Regional Total	166.6	129.2
South Atlantic		
Delaware	2.4	1.9
Dist. of Colubmia	5.0	3.8
Florida	14.2	14.1
Georgia	15.5	14.9
Maryland	14.8	12.7
North Carolina	14.5	13.7
South Carolina	7.0	7.1
Virginia	16.3	15.2
W. Virginia	7.3	6.5
Regional Total	96.9	90.0
East South Central		
Alabama	10.4	10.1
Kentucky	9.8	9.3
Mississippi	7.5	7.0
Tennessee	10.5	10.3
Regional Total	38.3	36.6
Pacific		
California	46.3	44.7
Oregon	10.5	10.4
Washington	12.5	24.6
Regional Total	69.3	79.7

	1900	2000
East North Central		
Illinois	41.0	33.5
Indiana	17.8	14.5
Michigan	33.3	28.7
Ohio	29.9	26.0
Wisconsin	14.4	11.9
Regional Total	136.4	114.6
West South Central		
Arkansas	9.9	9.3
Louisiana	11.3	11.0
Oklahoma	11.5	10.5
Texas	47.3	45.5
Regional Total	80.0	76.3
West North Central		
Iowa	8.9	7.8
Kansas	6.6	5.9
Minnesota	14.9	12.8
Missouri	14.0	12.2
Nebraska	5.1	4.5
North Dakota	2.0	1.7
South Dakota	1.8	1.5
Regional Total	53.4	46.5
Mountain		
Arizona	5.4	5.4
Colorado	12.2	11.4
Idaho	4.1	3.9
Montana	3.3	3.1
Nevada	1.5	1.5
New Mexico	3.3	3.0
Utah	5.2	4.5
Wyoming	2.8	2.5
Regional Total	37.7	35.1
Total U. S.	751.5	661.0

Source: SEAS Program. June, 1981. The Mitre Corp./U.S. Department of Energy.

*The Residential/Commercial Sector includes the consumption of fossil fuels, solar energy, and wood.

Table 6.8

Sector: Industrial Processes*
Projected Emissions: SO_2 (10^3 metric tons)

	1990	2000
New England		
Connecticut	0.2	0.2
Maine	3.0	2.5
Massachusetts	1.5	1.7
New Hampshire	2.9	2.3
Rhode Island	0.1	0.2
Vermont	0	0
Regional Total	7.7	6.8
Mid Atlantic		
New York	13.9	11.6
New Jersey	28.9	26.9
Pennsylvania	78.2	74.5
Regional Total	121.0	113.1
South Atlantic		
Delaware	10.3	10.4
Dist. of Columbia	0	0
Florida	86.0	104.5
Georgia	25.0	23.3
Maryland	9.3	8.2
North Carolina	74.5	108.6
South Carolina	13.0	13.6
Virginia	15.3	14.6
W. Virginia	20.1	16.9
Regional Total	253.4	300.1
East South Central		
Alabama	46.1	44.2
Kentucky	11.7	14.0
Mississippi	14.4	14.9
Tennessee	12.3	13.9
Regional Total	84.5	87.0
Pacific		
California	74.5	68.3
Oregon	9.0	7.9
Washington	20.3	17.3
Regional Total	103.7	93.5

	1990	2000
East North Central		
Illinois	43.8	58.1
Indiana	18.0	17.0
Michigan	12.6	12.6
Ohio	28.3	36.3
Wisconsin	2.7	2.3
Regional Total	105.5	126.3
West South Central		
Arkansas	16.0	17.2
Louisiana	105.5	111.0
Oklahoma	15.5	15.5
Texas	230.6	239.7
Regional Total	367.6	383.4
West North Central		
Iowa	7.2	8.6
Kansas	14.6	15.4
Minnesota	1.6	1.4
Missouri	6.4	6.4
Nebraska	1.7	2.1
North Dakota	17.3	66.5
South Dakota	1.2	19.5
Regional Total	50.0	109.9
Mountain		
Arizona	16.4	23.6
Colorado	5.2	14.5
Idaho	42.2	65.6
Montana	11.9	31.7
Nevada	1.2	1.5
New Mexico	12.7	19.5
Utah	8.8	18.1
Wyoming	6.2	14.6
Regional Total	104.5	189.3
Total U. S.	1 197.9	1 409.3

Source: SEAS Program. June, 1981. The Mitre Corp./U.S, Department of Energy

*Industrial Processes include the Pulp/Paper, Inorganic Chemical, Organ Chemical, Stone and Clay Products, Iron and Steel, Fertilizer, Fiberglass, Coal Mining, Gas Processing/Distribution/ Extraction, Oil Distribution/Extraction, Petroleum Refining, Nuclear Processing/Distribution and Municipal Sewage/Waste industries.

Table 6.9

Sector: Industrial Processes*
Projected Emissions: NO_x (10^3 metric tons)

	1990	2000
New England		
Connecticut	0.6	0.6
Maine	1.7	2.2
Massachusetts	1.7	1.8
New Hampshire	1.2	1.0
Rhode Island	0.1	0.1
Vermont	0.2	0.4
Regional Total	5.5	6.1
Mid Atlantic		
New York	8.3	5.7
New Jersey	30.5	27.6
Pennsylvania	34.0	38.3
Regional Total	72.8	71.6
South Atlantic		
Delaware	3.2	2.9
Dist. of Columbia	0.1	0.1
Florida	9.7	12.0
Georgia	63.0	73.5
Maryland	6.3	6.0
North Carolina	8.4	11.5
South Carolina	4.7	6.3
Virginia	3.9	4.2
W. Virginia	19.8	17.2
Regional Total	119.1	133.6
East South Central		
Alabama	20.5	20.1
Kentucky	9.5	9.8
Mississippi	7.6	8.3
Tennessee	4.6	5.1
Regional Total	42.3	43.3
Pacific		
California	76.5	66.1
Oregon	2.2	2.2
Washington	17.4	15.1
Regional Total	96.1	83.4

	1990	2000
East North Central		
Illinois	24.7	43.9
Indiana	10.3	9.9
Michigan	9.0	8.8
Ohio	14.1	24.2
Wisconsin	3.4	3.7
Regional Total	61.5	90.5
West South Central		
Arkansas	5.5	6.1
Louisiana	89.4	82.7
Oklahoma	19.2	19.2
Texas	142.1	133.4
Regional Total	256.2	241.4
West North Central		
Iowa	5.3	6.4
Kansas	28.4	28.2
Minnesota	3.5	3.7
Missouri	4.6	4.5
Nebraska	4.2	4.0
North Dakota	43.9	161.5
South Dakota	1.1	20.4
Regional Total	90.9	228.5
Mountain		
Arizona	4.4	4.4
Colorado	6.0	25.6
Idaho	0.7	1.2
Montana	20.4	85.0
Nevada	1.0	1.0
New Mexico	20.8	38.6
Utah	5.2	23.5
Wyoming	11.2	36.2
Regional Total	69.6	215.5
Total U. S.	814.0	1 114.0

Source: SEAS Program. June, 1981. The Mitre Corp./U.S, Department of Energy

*Industrial Processes include the Pulp/Paper, Inorganic Chemical, Organic Chemicals, Stone and Clay Products, Iron and Steel, Fertilizer, Fiberglass, Coal Mining, Gas Processing/Distribution/Extraction, Oil Distribution/Extraction, Petroleum Refining, Nuclear Processing/Distribution, and Municipal Sewage/Waste industries

Table 6.10

Sector: Transportation*
Projected Emissions: SO_2 (10^3 metric tons)

	1990	2000
New England		
Connecticut	10.2	12.8
Maine	3.0	3.5
Massachusetts	17.4	22.3
New Hampshire	2.1	2.5
Rhode Island	2.9	3.5
Vermont	1.4	1.6
Regional Total	36.9	46.4
Mid Atlantic		
New York	39.4	48.0
New Jersey	25.6	37.7
Pennsylvania	41.5	52.2
Regional Total	106.5	132.9
South Atlantic		
Delaware	1.7	2.2
Dist. of Columbia	2.4	3.3
Florida	31.8	43.4
Georgia	21.8	27.8
Maryland	13.2	17.5
North Carolina	18.5	24.0
South Carolina	9.6	11.3
Virginia	19.4	25.0
W. Virginia	6.2	7.5
Regional Total	124.5	161.9
East South Central		
Alabama	13.5	16.8
Kentucky	12.5	15.8
Mississippi	7.5	9.3
Tennessee	18.9	24.4
Regional Total	52.3	66.3
Pacific		
California	94.2	120.7
Oregon	10.8	13.7
Washington	14.4	17.9
Regional Total	119.4	152.4

	1990	2000
East North Central		
Illinois	35.8	45.0
Indiana	23.8	30.5
Michigan	29.5	36.9
Ohio	42.3	54.7
Wisconsin	15.1	18.6
Regional Total	146.5	185.8
West South Central		
Arkansas	8.6	10.9
Louisiana	12.2	15.2
Oklahoma	12.3	15.6
Texas	60.0	76.5
Regional Total	93.1	118.2
West North Central		
Iowa	11.8	14.5
Kansas	8.6	10.8
Minnesota	13.8	17.5
Missouri	18.5	23.5
Nebraska	6.5	8.1
North Dakota	2.6	3.3
South Dakota	2.5	3.2
Regional Total	64.4	80.9
Mountain		
Arizona	12.7	17.2
Colorado	10.4	13.5
Idaho	2.6	3.3
Montana	3.7	4.6
Nevada	3.7	5.2
New Mexico	5.9	7.5
Utah	5.6	7.3
Wyoming	2.3	2.8
Regional Total	47.0	61.4
Total U. S.	790.5	1 006.1

Source: SEAS Program. June, 1981. The Mitre Corp./U.S. Department of Energy

*The Transportation sector includes Light Duty Vehicles, Light Duty Trucks, Heavy Duty Gasoline, Heavy Duty Diesel, Off Highway Vehicles and Vessels.

Table 6.11

Sector: Transportation*
Projected Emissions: NO_x (10^3 metric tons)

	1990	2000
New England		
Connecticut	100.8	125.5
Maine	30.5	36.0
Massachusetts	172.0	217.9
New Hampshire	21.1	27.3
Rhode Island	28.9	35.0
Vermont	14.1	17.5
Regional Total	367.4	459.2
Mid Atlantic		
New York	399.5	486.4
New Jersey	251.0	309.4
Pennsylvania	408.9	502.9
Regional Total	1 059.5	1 298.6
South Atlantic		
Delaware	17.2	21.4
Dist. of Columbia	23.5	34.1
Florida	321.4	441.6
Georgia	220.5	278.2
Maryland	132.1	175.1
North Carolina	186.1	246.1
South Carolina	96.2	110.9
Virginia	195.5	252.9
W. Virginia	60.2	70.0
Regional Total	1 252.5	1 630.3
East South Central		
Alabama	132.1	159.5
Kentucky	125.1	159.5
Mississippi	73.5	88.5
Tennessee	190.0	249.0
Regional Total	520.6	656.6
Pacific		
California	911.6	1 105.0
Oregon	105.5	127.5
Washington	141.5	173.2
Regional Total	1 158.7	1 405.6
East North Central		
Illinois	359.6	448.5
Indiana	231.5	285.0
Michigan	293.2	362.8
Ohio	414.4	525.4
Wisconsin	149.4	182.9
Regional Total	1 448.0	1 804.5
West South Central		
Arkansas	84.5	104.1
Louisiana	120.4	145.9
Oklahoma	121.2	147.8
Texas	586.4	716.9
Regional Total	912.4	1 114.7
West North Central		
Iowa	115.7	137.2
Kansas	84.5	102.2
Minnesota	137.2	171.2
Missouri	182.9	225.6
Nebraska	64.1	77.8
North Dakota	25.8	30.2
South Dakota	25.8	32.1
Regional Total	636.0	776.3
Mountain		
Arizona	123.5	160.5
Colorado	103.2	131.4
Idaho	26.5	32.1
Montana	36.7	43.8
Nevada	38.3	51.5
New Mexico	57.8	70.0
Utah	54.7	67.1
Wyoming	21.9	26.3
Regional Total	462.7	582.7
Total U. S.	7 817.7	9 728.5

Source: Mobile 2 Transportation Model (U. S. EPA, April, 1981) disaggregated to state level via state fractions developed by the Mitre Corp.

*The Transportation sector includes Light Duty Vehicles, Light Duty Trucks, Heavy Duty Gasoline, Heavy Duty Diesel, Off Highway Vehicles, and Vessels.

TABLE 6.12

National Projections of Utility Emissions & Fuel Use

	1980	1990	2000
SO_2 Emissions (million tons)	17.4	17.5	17.9
NO_x Emissions (million tons)	6.4	7.5	9.6
Coal Use (10^{15} Btus)	11.9	15.9	24.1
Oil Use (10^{15} Btus)	2.7	2.2	1.2
Gas Use (10^{15} Btus)	3.7	2.7	1.6
Nuclear Power (10^{15} Btus)	2.5	5.0	7.2
Hydro, Other (10^{15} Btus)	3.1	3.5	4.6
Generation (10^{12} kwh)	2 290	2 840	3 740

TABLE 6.13

Projected Generation by Census Region

(terawatt hours)

	1990	2000
New England	89	104
Middle Atlantic	301	353
East North Central	500	665
West North Central	211	281
South Atlantic	524	695
East South Central	260	332
West South Central	410	576
Mountain	215	310
Pacific	331	424
TOTAL UNITED STATES	2 840	3 739

Note: Numbers do not equal totals due to rounding.

TABLE 6.14

Utility Announced Generating Capacity Additions (GW)

	Coal Steam	Other Fossil Steam	Nuclear Steam	Fossil Nonsteam	Other
1981-1985	68.2	1.6	46.9	7.7	10.9
1986-1990	67.5	.7	28.3	3.3	13.2
1991-1995	10.1	0.0	12.1	.2	1.0
1996-2000	.7	0.0	8.5	0.0	.2
TOTAL	146.5	2.3	95.7	11.2	25.3

TABLE 6.15

Design Capacity Factors Used in the Analysis

	Existing Plants				New Plants
	1985	1990	1995	2000	
Coal Steam	-	-	-	-	.65
Oil Steam	.4	.3	.3	.25	.65
Gas Steam	.4	.3	.3	.25	.65
Oil Nonstream	-	-	-	-	.10
Gas Nonstream	-	-	-	-	.10
Hydroelectric, Other	-	-	-	-	.60
Nuclear Steam	-	-	-	-	.65

* unchanged from base year, varies by unit.

TABLE 6.17
Utility
Fossil Fuel Use by Region
(10^{12} Btu)

	1990	2000
New England	488	652
Coal	230	507
Oil	224	115
Gas	33	30
Middle Atlantic	2 115	2 164
Coal	1 457	1 845
Oil	508	224
Gas	150	94
East North Central	4 229	5 625
Coal	3 921	5 456
Oil	195	52
Gas	113	117
West North Central	1 923	2 402
Coal	1 732	2 244
Oil	52	52
Gas	139	107
South Atlantic	4 031	5 458
Coal	3 344	5 012
Oil	529	329
Gas	166	117
East South Central	1 925	2 296
Coal	1 813	2 227
Oil	31	27
Gas	81	42
West South Central	3 328	4 385
Coal	1 865	3 504
Oil	73	47
Gas	1 391	834
Mountain	1 608	2 289
Coal	1 446	2 202
Oil	31	22
Gas	131	65
Pacific	1 130	1 428
Coal	165	1 028
Oil	442	196
Gas	553	204
Total	20 774	26 699
Coal	15 972	24 024
Oil	2 076	1 063
Gas	2 726	1 611

TABLE 6.18
RNSPS and PSD SO_2 Standards by State
(Annual lbs/mmBtu)

State	RNSPS	PSD
Alabama	0.60	0.60
Alaska	0.60	0.42
Arizona	0.26	0.09
Arkansas	0.60	0.60
California	0.60	0.42
Colorado	0.32	0.11
Connecticut	0.60	0.60
Delaware	0.60	0.60
District of Columbia	0.40	0.40
Florida	0.60	0.60
Georgia	0.60	0.60
Hawaii	0.60	0.42
Idaho	0.60	0.42
Illinois	0.60	0.60
Indiana	0.60	0.60
Iowa	0.60	0.60
Kansas	0.80	0.60
Kentucky	0.60	0.60
Louisiana	0.60	0.60
Maine	0.60	0.60
Maryland	0.60	0.60
Massachusetts	0.54	0.54
Michigan	0.60	0.60
Minnesota	0.60	0.60
Mississippi	0.60	0.60
Missouri	0.60	0.60
Montana	0.49	0.16
Nebraska	0.60	0.33
Nevada	0.22	0.07
New Hampshire	0.60	0.60
New Jersey	0.60	0.60
New Mexico	0.42	0.14
New York	0.60	0.60
North Carolina	0.52	0.52
North Dakota	0.60	0.21
Ohio	0.60	0.60
Oklahoma	0.10	0.09
Oregon	0.60	0.42
Pennsylvania	0.60	0.60
Rhode Island	0.60	0.60
South Carolina	0.60	0.60
South Dakota	0.34	0.11
Tennessee	0.60	0.60
Texas	0.51	0.17
Utah	0.26	0.09
Vermont	0.41	0.41
Virginia	0.44	0.44
Washington	0.41	0.14
West Virginia	0.60	0.60
Wisconsin	0.60	0.60
Wyoming	0.39	0.13

TABLE 6.19

1971 and 1979 NSPS NO_x Standards (lbs NO_x per 10^6 Btu's)

	1971 NSPS*	1979 NSPS**
Bituminous Coal	.70	.60
Lignite***	.60	.60
Oil	.30	.30
Gas	.20	.20

* Fossil fuel fired steam generators for which construction was commenced after August 17, 1971.

** Electric utility steam generators for which construction was commenced after September 18, 1978.

*** Cyclone fired units burning lignite and on-line by 1980 were assumed to be limited by the .8 pound standard in 60.44(a)(5).

TABLE 6.20

NO_x Emission Factors by Fuel Type and Boiler Type

COAL (lbs/ton)

	Bituminous Coal		Lignite	
Boiler Type: Bottom	Wet	Dry	Wet	Dry
Firing Type				
Front Wall/Opposed Wall	34	21	14	14
Tangential	34	15	8	8
Stoker/Vertical	14	14	6	6
Cyclone	37	37	17	17

OIL AND GAS STEAM

	Oil	Gas
Firing Type	(pounds per 1000 Gallons)	(pounds per 1000 Mcf)
Front Wall/Opposed Wall	67	550
Tangential	42	275
Stoker/Vertical	105	550
Cyclone	67	550

OIL AND GAS NONSTEAM

Internal Combustion	469.8	3,400.0
Combustion Turbines	67.8	413.0

TABLE 6.21

Equipment Costs (in thousands of $ 1980)

Type of Fuel Burned in Boiler	Boiler Size in MMBtu/Hr.				
	20	70	170	370	560
Bituminous Coal					
High-Sulfur	2 106	4 827	9 111	17 315	23 799
Medium-Sulfur	2 092	4 731	8 838	17 035	23 402
Low-Sulfur	2 087	4 712	8 970	16 977	23 321
High-Sulfur with Scrubber	2 704	7 028	12 090	23 417	32 471
Medium-Sulfur with Scrubber	--	--	--	22 248	30 656
Low-Sulfur with Scrubber	2 593	6 080	11 755	22 170	30 567
Subbituminous Coal					
Medium-Sulfur	2 166	4 987	9 568	18 103	24 946
Low-Sulfur	2 163	4 968	9 529	18 052	24 852
Medium Sulfur with Scrubber	N/A	N/A	11 640	23 317	32 200
Low-Sulfur with Scrubber	2 687	6 390	12 411	23 453	32 263
Residual Oil					
High-Sulfur	974	1 997	3 576	6 139	8 623
Medium-Sulfur	888	1 765	3 131	5 274	7 419
Low-Sulfur	873	1 725	3 027	5 123	7 210
Distillate Oil	831	1 622	2 819	4 687	6 588
Natural Gas	787	1 518	2 582	4 251	5 966

TABLE 6.22

Annual Fixed O&M Costs (thousands of $ 1980)

Type of Fuel Burned In Boiler	Boiler Size in MMBtu/Hr.				
	20	70	170	370	560
Bituminous Coal					
High-Sulfur	129	306	579	1 064	1 405
Medium-Sulfur	131	306	588	1 060	1 385
Low-Sulfur	131	306	589	1 059	1 381
High-Sulfur with Scrubber	178	434	838	1 560	2 107
Medium-Sulfur with Scrubber	--	--	--	1 499	2 015
Low-Sulfur with Scrubber	166	399	815	1 388	1 866
Subbituminous Coal					
Medium-Sulfur	131	306	588	1 060	1 385
Low-Sulfur	129	307	577	1 065	1 408
Medium Sulfur with Scrubber	--	--	857	1 511	2 020
Low-Sulfur with Scrubber	166	401	794	1 399	1 870
Residual Oil					
High-Sulfur	84	209	389	671	897
Medium-Sulfur	84	209	389	671	897
Low-Sulfur	84	209	389	671	897
Distillate Oil	84	209	389	671	897
Natural Gas	70	170	320	552	733

TABLE 6.23

Annual Variable O&M Costs*
(thousands of $ 1980)

Type of Fuel Burned In Boiler	Boiler Size in MMBtu/Hr. 20	70	170	370	560
Bituminous Coal					
High-Sulfur	36	110	247	558	817
Medium-Sulfur	35	115	262	603	852
Low-Sulfur	35	116	362	612	860
High-Sulfur with Scrubber	114	378	886	1 935	2 892
Medium-Sulfur with Scrubber	--	--	--	1 423	2 110
Low-Sulfur with Scrubber	74	237	732	1 196	1 773
Subbituminous Coal					
Medium-Sulfur	34	115	262	603	852
Low-Sulfur	36	109	241	556	814
Medium Sulfur with Scrubber	--	--	668	1 393	2 071
Low-Sulfur with Scrubber	73	230	561	1 171	1 740
Residual Oil					
High-Sulfur	10	32	79	167	247
Medium-Sulfur	12	41	95	203	302
Low-Sulfur	13	43	100	213	316
Distillate Oil	14	44	104	220	328
Natural Gas	5	18	39	82	121

*Assumes 100 percent utilization

TABLE 6.24

Boiler Fuel Use By Industry By Size By Utilization Rate (Percent of Fuel Use)

Industry/ Boiler Size	Utilization Rate 10 to 19	20 to 29	30 to 39	40 to 49	50 to 59	60 to 69	70 to 79	80 to 100
Food								
100-249	7	15	18	18	19	6	9	23
250-500	1	4	2	14	44	17	11	6
500+	-	-	-	-	-	-	-	-
Paper								
100-249	2	4	8	9	19	14	22	23
250-500	1	2	5	10	20	16	13	33
500+	4	2	6	10	25	14	22	16
Chemicals								
100-249	1	4	5	8	17	22	20	23
250-500	1	3	3	8	17	21	19	29
500+	1	1	-	16	12	-	22	48
Pet Refining								
100-249	1	2	9	3	20	31	17	16
250-500	2	1	7	1	10	25	22	33
500+	-	2	5	4	10	11	53	16
Primary Metals								
100-249	8	18	19	5	18	4	11	31
250-500	9	4	8	9	18	8	27	17
500+	8	2	7	27	9	20	14	12
All Others								
100-249	7	13	13	11	14	8	12	22
250-500	3	3	8	11	14	13	22	26
500+	4	-	6	6	5	3	32	43

TABLE 6.25

New Industrial Boiler Fuel Demand Cumulative over the period 1982 to 2000 (10^{12} Btu)

New England	
Connecticut	17.0
Maine	25.0
Massachusetts	17.0
New Hampshire	7.1
Rhode Island	3.8
Vermont	1.8
Regional Total	71.7

Mid Atlantic	
New York	92.0
New Jersey	76.0
Pennsylvania	160.0
Regional Total	328.0

South Atlantic	
Delaware	9.8
Dist. of Columbia*	--
Florida	50.0
Georgia	60.0
Maryland	28.0
North Carolina	63.0
South Carolina	45.0
Virginia	57.0
W. Virginia	49.0
Regional Total	361.8

East South Central	
Alabama	64.0
Kentucky	33.0
Mississippi	37.0
Tennessee	63.0
Regional Total	197.0

Pacific	
California	92.0
Oregon	23.0
Washington	40.0
Regional Total	155.0

East North Central	
Illinois	110.0
Indiana	74.0
Michigan	110.0
Ohio	160.0
Wisconsin	68.0
Regional Total	522.0

West South Central	
Arkansas	46.0
Louisiana	160.0
Oklahoma	14.0
Texas	350.0
Regional Total	570.0

West North Central	
Iowa	34.0
Kansas	23.0
Minnesota	25.0
Missouri	34.0
Nebraska	10.0
North Dakota	2.3
South Dakota	1.2
Regional Total	129.5

Mountain	
Arizona	8.8
Colorado	11.0
Idaho	8.1
Montana	6.8
Nevada	3.7
New Mexico	3.2
Utah	6.9
Wyoming	1.8
Regional	50.3

Total U. S.	2 385.3

*District of Columbia fuel use is included in the State of Maryland.

TABLE 6.26

Industrial Boiler Model

Assumed Sulfur Dioxide Emissions (Pounds Per MMBtu of Fuel Used)

	Mid-Point	Range Represented
Bituminous Coal		
High-Sulfur	5.0	More than 3.0
Medium-Sulfur	2.3	1.5 to 3.0
Low-Sulfur	1.2	0.8 to 1.5
High-Sulfur, with FGD*	1.2	0.8 to 1.5
Medium-Sulfur, with FGD	0.7	0.5 to 0.8
Low-Sulfur, with FGD	0.36	Less than 0.5
Subbituminous Coal		
Medium-Sulfur	2.3	1.5 to 3.0
Low-Sulfur	1.2	0.8 to 1.5
Medium-Sulfur, with FGD	0.7	0.5 to 0.8
Low-Sufur, with FGD	.36	Less than 0.5
Residual Oil		
High-Sulfur	2.0	More than 1.5
Medium-Sulfur	.8	0.5 to 1.5
Low-Sulfur	.3	0.2 to 0.5
Distillate Oil	.2	Less than 0.2
Natural Gas and All Hybrids**	-	---

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*This represents a 6 lb. high sulfur coal with 80 percent scrubbing.

**There are 14 hybrids. Each represents a boiler designed to burn a particular coal or oil type, but temporarily using natural gas.

TABLE 6.27

Process Heat Model
Assumed Sulfur Dioxide Emissions
(lbs./MMBtu of Fuel Used)

FUEL	EMISSIONS
High sulfur coal in kilns	0.50
Medium sulfur coal in kilns	0.23
Low sulfur coal in kilns	0.12
High sulfur coal	5.00
Medium sulfur coal	2.30
Low sulfur coal	1.20
High sulfur resid in kilns	.20
Medium sulfur resid in kilns	.08
Low sulfur resid in kilns	.03
High sulfur resid	2.00
Medium sulfur resid	0.80
Low sulfur resid	0.30
Distillate	0.20
Natural gas	0.00
Paper industry by-product fuel	0.80
Primary metals industry by-product fuel	1.10
Petroleum industry by-product fuel	0.00

TABLE 6.28

IBM NO_x Emission Factors

Fuel/Combustor Size	Installed pre-1974	Installed post-1974
Coal		
Over 250 MMBtu/hr	1.25 to 1.7	0.7
Under 250	0.6 to 0.7	0.6 to 0.7
Residual Oil		
Over 250	0.7	0.3
Under 250	0.4	0.4
Distillate Oil		
Over 250	0.7	0.3
Under 250	0.16	0.16
Natural Gas		
Over 250	0.7	0.2
Under 250	0.1	0.1

TABLE 6.29

PHM NO_x Emission Factors

Fuel/Combustor Size	
Coal	
Over 250 MMBtu/hr	1.25 to 1.7
Under 250	0.6 to 0.7
Residual Oil	
Over 250	0.7
Under 250	0.4
Distillate Oil	
Over 250	0.7
Under 250	0.16
Natural Gas	
Over 250	0.7
Under 250	0.1

TABLE 6.30

Average Sulfur to Copper Ratio in Smelter Charge

Smelter	S/Cu
Arizona	1.578
	1.629
	1.013
	1.307
	1.383
	0.743
	1.043
Montana	1.115
New Mexico	1.086
Nevada	1.445
Texas	1.045
Utah	0.909
Washington	1.263

Source: A. D. Little, Inc., "Economic Impact of NSPS on the Primary Copper Industry: An Assessment," Appendix E. pp. E-7 to E-20 (October 1974)

TABLE 6.31

Fuel Use (10^{15} Btu)

	Residential		Commercial	
	Space Conditioning	Total	Space Conditioning	Total
1980				
Oil	2.3	2.6	1.9	3.1
Natural Gas	3.3	5.3	2.1	2.3
Coal	0.1	0.1	0.1	0.1
Renewables	0.2	0.2	0	0
Electricity	0.8	2.5	0.7	1.8
Total	6.7	10.7	4.8	7.3
1990				
Oil	1.8	2.0	1.3	2.5
Natural Gas	3.1	5.1	2.3	2.6
Coal	0.2	0.2	0.1	0.1
Renewables	0.3	0.4	0.2	0.3
Electricity	1.0	2.9	1.0	2.3
Total	6.4	10.6	4.9	7.8
2000				
Oil	1.2	1.3	0.8	2.0
Natural Gas	2.7	4.9	2.4	2.9
Coal	0.2	0.2	0.1	0.1
Renewables	0.5	0.6	0.4	0.6
Electricity	1.4	3.4	1.5	2.9
Total	6.0	10.4	5.2	8.5

APPENDIX 7

7. DETAILED LIST OF CURRENT RESEARCH AND DEVELOPMENT PROJECTS

This Appendix contains a list of research projects related to the development of control technologies for SO_x and NO_x emissions. Included is a brief description of each project, a statement as to its relevance, scope, funding and expected output.

Projects 7.1 to 7.8 deal with sulfur or SO_x removal techniques for coal combustion. Projects 7.9 to 7.11 deal with low-NO_x burner development and demonstration. R & D projects for the control of NO_x emissions by combustion modifications or FGT are described in projects 7.12 to 7.19. Combined SO_x/NO_x control technologies are listed in projects 7.20 to 7.28.

NOTE: The telephone numbers given refering to IERL/RTP are not to be used for calls originating outside the U.S. government telephone network. The last 4 digits are correct, the 3 digit number "629" is however incorrect and should be changed to "(919)-541".

7.1 Development/Evaluation of Dry FGD Technology

Objective: To develop and evaluate a potentially more reliable and cost-effective alternative to wet FGD systems; to assess the ability of dry FGD systems to achieve recent utility boiler NSPS and industrial boilers NSPS (under development).

Approach: Dry SO_2 control systems show potential for significant economic/reliability improvements when applied to SIP boilers and western utilities. They may have application to high sulfur coal as well. Annual evaluation of dry scrubbing technology state-of-the-art developments and commercial applications will be conducted. An in-house IERL-RTP dry FGD pilot plant will be used to evaluate methods for improving the performance and reducing the costs of dry FGD systems. Field evaluations of selected pilot/prototype spray-dryer/baghouse and dry injection systems will be undertaken to determine the relationship of key process parameters. Field evaluations of industry-funded full-scale dry scrubbing units will also be conducted to determine performance and reliability of first generation dry systems. Economic studies will also be performed to evaluate the cost effectiveness of using physical coal cleaning and dry FGD systems to control sulfur emissions from high sulfur coals.

Rationale: Impetus for the development and evaluation of dry FGD technology stems from the revised utility boiler NSPS which limits SO_2 emissions on a variable scale over a wide spectrum of fuel sulfur content. Dry FGD appears to present the most cost-effective option for the 70% level required for typical Western coals and may also be the preferred economic choice for certain high-sulfur Eastern coals as well. Compared to the present generation of wet FGD systems, dry FGD technology is expected to be less complex (more reliable), require less water and energy, produce dry wastes and require lower capital/operating/maintenance costs.

Resources ($1000's):

FY81	FY82	FY83
1025	283	100

Milestones:

° Complete final reports describing results of pilot/prototype testing of spray-dryer/baghouse and alkali injection/baghouse systems applied to utility boilers;	2/82, 5/82
° Complete reports of industrial boiler spray dryer field evaluation (high sulfur coal);	7/82, 7/83 7/82, 7/83

APPENDIX 7

° Complete annual technology evaluation reports;	10/82, 10/83
° Modify IERL-RTP in-house FGD pilot plant to incorporate spray-dryer/baghouse;	2/83
° Complete report describing results of field evaluations of 1st generation full scale utility spray dryer systems; and	6/82, 6/83
° Complete report assessing economics and applicability of physical coal cleaning and dry scrubbing for SO_2 emission control.	12/83

Contact: J. Kilgroe, IERL/RTP Project Officer, 629-2854

7.2 Research on Fundamentals of Electrostatic Augmentation of Fabric Filtration

Objective: Develop a technological basis for electrically enhanced fabric filtration in baghouse operating on utility and industrial boilers and spray dryers, controlling SO_x.

Approach: Field assessments of Electrostatic Augmentation of Fabric Filtration (ESFF) are being made in a pilot plant utilizing both pulse jet and reverse air cleaning mechanisms. Laboratory studies are planned to explore advanced ESFF modifications of electrodes or filter bags for incorporation into the field operation at any convenient stage. Finished assessments are to include cost information on ESFF technology. In-house experiments are designed to determine the mechanism by which ESFF operates to give improved filtration, and to develop the technology required to extend ESFF to filtration systems on spray dryers for SO_x removal.

Rationale: Fabric filtration is a preferred method of emission control in some industrial and utility applications because of its recognized high efficiency. The ESFF concept shows promise of removing the energy penalty associated with fabric filtration by as much as 50%, thereby providing support for 1983 and subsequent reviews of industrial and utility boiler New Source Performance Standards. The potential for ESFF in pulse-jet baghouses has been strengthened by the discovery that the inside support cage can double as electrodes to generate the electrical field. For reverse air application, an investigation into the optimum electrical characteristics for a fabric-electrode system is needed. Extension of ESFF for use in dry SO_x systems promises to provide a very cost effective pollution control system for both particulate and SO_x control.

Resources ($1000's):

FY81	FY82	FY83
1139	700	670

Milestones:

° ESFF pulse-jet pilot plant report;	4/82
° Report on advanced ESFF laboratory work;	8/82
° Complete ESFF reverse air work on 1000 ACFM pilot unit;	9/82
° Complete in-house investigation of ESFF effectiveness on spray-dryer emissions; and	7/83

- Complete testing on industrial boiler with ESFF baghouse. 2/84

Contacts: L. Hovis, IERL/RTP, Project Officer, 629-2925

7.3 Development and Evaluation of Two-Stage Electrostatic Precipitators

Objective: To evaluate, at large pilot scale, two-stage electrostatic precipitator concepts and to increase the design certainty of two-stage electrostatic precipitators (ESP) and maximize the performance and economics of such systems by understanding the fundamentals of the two-stage ESP.

Approach: Performance and economics of two-stage ESP based on the trielectrode and cold pipe prechargers will be evaluated using a 30,000 and a 10,000 ACFM pilot scale system. Theoretical bench scale and pilot scale studies will be conducted to develop sound theory, design models, and operational procedures for two-stage ESP. Pilot plant research will be conducted to develop improved downstream collectors for two-stage ESP. Planned work includes investigation of electron charging, pulse power, modified electrode geometries and operation procedures.

Rationale: Pilot plant studies have shown that first generation two-stage ESP require 40-50% less capital investment than conventional particulate control technology. However, because of limited design certainty, vendors, archetects and engineers, and users, who attended a recent peer review of the program, have all said that rapid commercialization of the technology requires additional pilot plant evaluation and an improved understanding of the two-stage ESP technology.

Resources ($1000's):

FY81	FY82	FY83
1424	815	650

Milestones:

° Complete shakedown of transportable ESP;	4/82
° Evaluation report on 30,000 ACFM pilot plant using one type of low sulfur coal and trielectrode precharger;	10/82
° Publish performance model for first generation two-stage ESP;	12/82
° Complete first field test of trielectrode system on second type of low sulfur coal using transportable ESP;	12/82

° Complete evaluation of cold pipe 2/83 precharger;	2/83
° Evaluation report for total low sulfur burning utility industry;	12/83
° Dismantle transportable ESP and restore site; and	6/84
° Publish design manual for two-stage electrostatic precipitators.	12/84

<u>Contacts</u>: L. Sparks, IERL/RTP, Project Officer, 629-2925.

7.4 Development/Demonstration of an Adipic Acid-Enhanced Limestone FGD Process

Objective: To improve the performance, reliability, and cost-effectiveness of the first generation FGD technology (lime/limestone wet scrubbing) used for control of SO_x emissions from coal-fired boilers.

Approach: Complete pilot/prototype/full-scale investigations using chemical additives such as adipic acid in order to improve the performance, reliability, applicability and economics of lime/limestone FGD systems. Continue laboratory scale evaluations to address the remaining technological issues. Emphasis will be on process performance improvements in the areas of alkali utilization, SO_2 removal efficiency, waste disposal properties and water management. Support studies assessing economics of site-specific retrofit applications and secondary environmental impacts will also be undertaken. The range of applicability to both new and existing systems will be determined. The performance of any commercial applications of the technology shall also be monitored during their first year of operation.

Rationale: The adipic acid-enhanced limestone FGD process has been demonstrated on a full-scale operating utility boiler system. However, it is necessary to stimulate industry to bridge the gap between demonstration and commercialization of the technology. It is also necessary to allay any residual concerns the industry may have about the technology. The primary stimulant is obviously economic benefit, and the primary concern to date is environmental impact. Therefore, by addressing these areas, the technology should proceed to commercialization as rapidly as possible and would be available as a control technique for an acid rain control strategy.

Resources ($1000's):

FY81	FY82	FY83
570	200	50

Milestones:

° Complete report on prototype (10 MW) evaluation at EPA's Shawnee Alkali Scrubbing Test Facility;	2/82
° Complete report on the full scale (20 MW) 2/82 demonstration at an industrial boiler facility;	2/82
° Publish Capsule Report on Adipic Acid Enhanced Limestone FGD Processes;	5/82

° Complete report on the full scale utility (200 MW) demonstration at Springfield City Utilities;	5/82
° Complete report on laboratory-scale evaluation of buffer additives;	6/82
° Conduct site specific economic evaluation of a retrofit application of adipic acid technology;	10/82
° Complete report documenting environmental impacts of adipic acid utilization;	10/82
° Complete report documenting first year performance of adipic acid/limestone systems on commercial applications; and	5/83
° Complete report documenting the technical and economic feasibility of adipic acid enhanced FGD systems for new and existing sources.	9/83 9/83

Contacts: D. Mobley, IERL/RTP, 629-2578

7.5 In-House Research & Development on FGD Processes

Objective: Evaluation of new concepts and developments in FGD technology through in-house research designed to improve scrubber performance, reliability, cost-effectiveness, and energy efficiency.

Approach: Use existing EPA in-house pilot-scale FGD facilities to acquire data on improved variations of limestone and dual alkali FGD processes. Research will include advanced technologies such as organic acid enhancement of limestone scrubbing and sodium-based dual alkali scrubbing using limestone regenerants. Evaluations of problems confronting operating FGD systems will also be conducted, such as the impact of high chloride concentrations on FGD process chemistry. Cooperative projects (including cost-sharing) with vendors and utility companies will be emphasized in addressing these real world problems. In addition, modification of the in-house pilot plant facilities will be pursued to provide capability to evaluate spray-dryer/baghouse processes, which are potentially more cost-effective than the traditional wet scrubbing processes for SO_2 control.

Rationale: In-house pilot-scale research on FGD technology is a cost-effective approach for screening and evaluating new concepts and process modifications prior to more costly large scale development, demonstration, and/or commercial application.

Resources ($1000's):

FY81	FY82	FY83
650	320	300

Milestones:

° Complete pilot studies on the effect of high chloride concentrations on the process chemistry of limestone FGD systems;	6/82
° Complete pilot studies of sodium-based dual alkali scrubbing using limestone regenerants;	9/82
° Complete pilot studies using organic acids (such as adipic or glycolic) to enhance the performance of alkaline ash scrubbing systems;	1/83

° Modify IERL-RTP in-house FGD pilot plant to incorporate spray-dryer/baghouse (Funded under "Development/Evaluation of Dry FGD Technology");	2/83
° Complete pilot studies to optimize process flow diagram for regeneration section of dual alkali scrubber; and	9/83
° Complete pilot studies evaluating feasibility of converting lime systems to limestone with organic acid enhancement.	9/83

<u>Contacts</u>: D. Mobley, IERL/RTP, 629-2578
N. Kaplan, IERL/RTP, 629-2556

7.6 FGD Technology Assessment

Objective: To assess the state-of-the-art of flue gas desulfurization technology and facilitate the transfer of process innovations to the user community.

Approach: Engineering analysis of FGD technology shall be completed to determine the most cost effective SO_2 control alternative. A report will be compiled which assembles the results of the field studies conducted to assess the current state-of-the-art in FGD technology including waste disposal. Technology transfer activities include a national symposium every 18 months which is the major forum for disseminating results to industry, vendor, and government personnel. In addition, the utility FGD survey, and associated data base, will be maintained. This system provides operational and maintenance data, and application trends to users including State and Regional fffices.

Rationale: It is necessary to continually assess new technology developments to ensure that industry is aware of the most cost effective control technologies and to channel R & D resources into the most productive areas. Concurrent to this, technology assistance and information must be provided to the user community. This includes not only personnel in industry but also in state and regional offices, who require technical information regarding permit evaluations. Personnel in these offices frequently lack background and training in FGD technology; provisions to provide technical assistance and information result in a benefit to EPA by helping ensure that properly permitted FGD systems are in use.

Resources ($1000's):

FY81	FY82	FY83
2056	158	50

Milestones:

° Maintain Utility FGD Information System Data quarterly Base for Regional Office permit evaluation support;	quarterly
° Conduct and publish proceedings of Seventh FGD Symposium;	5/82, 8/82
° Conduct and publish proceedings of Eighth FGD Symposium;	11/83, 2/84

- Complete reports documenting the following field test evaluations:
  - Wellman-Lord/Allied Process 6/81
  - Shawnee Alkali Scrubbing Test Facility 2/82
  - Dual Alkali Process (A.B. Brown) 3/82
  - Dual Alkali Process (LG&E) 3/82
  - Limestone/Adipic Acid Process 5/82
  - Dry FGD (Spray Dryer/Baghouse or ESP) 7/82
  - Aqueous Carbonate Process 1/83
- Complete report on Full-Scale Utility Waste Disposal Study; 6/83
- Complete economic assessment of FGD process alternatives; and 9/82
- Complete FGD Technology Assessment. 1/83

Contacts:
C. Masser, IERL/RTP, 629-2578
D. Mobley, IERL/RTP, 629-2578
N. Kaplan, IERL/RTP, 629-2556

7.7 Coal Cleaning Assessment

Objective: To assess the use of coal cleaning for complying with SO_2 emission regulations.

Approach: Engineering and economic studies will be made to assess state-of-the-art and advanced coal cleaning techniques. Tests will be conducted to evaluate the ability of the Homer City Coal Cleaning plant to desulfurize coal for compliance with state and federal SO_2 emission regulations. Supporting studies at Homer City will be used to develop methods for predicting the in-situ physical desulfurization potential (washability) of coal seams. Coal washability and plant performance data will be used to develop improved predictive models needed for use of coal cleaning as an SO_2 emission control method. An economic computer model capable of comparing the costs of physical coal cleaning and lime/limestone FGD, with FGD alone, will be developed.

Rationale: It is not currently possible to predict the manner in which coal washability varies within a coal seam. Also, the costs and effectiveness of state-of-the-art and advanced coal cleaning processes in desulfurizing coal of changing properties is unknown. Studies of operating plants and new processes are needed to develop models for use in the design and operation of coal cleaning systems for the production of compliance fuels.

Resources ($1000):

FY81	FY82	FY83
200	0	0

Milestones:

° Complete interim report on Homer City Coal Cleaning Plant Test and Evaluation Program;	4/82
° Complete report on Advanced Energy Dynamics electrostatic coal cleaning process;	6/82
° Publish Phase I report on geological phenomena which control coal ash and sulfur variability in the Homer City Reserves;	7/82

- Complete interim report and users manual on PCC & FGD Economics Computer program; 9/82
- Publish Homer City Preparation plant start-up and acceptance test report; 12/82
- Publish Phase I report on correlations between geochemical/geophysical properties and coal washability; 6/83
- Publish report on methods for estimating the in-situ variability of the physical washability of coal; and 9/83
- Complete Final Report on Homer City Coal Cleaning Demonstration; 6/84

Contacts: J. Kilgroe, IERL/RTP Project Officer, 629-2854

7.8 Coal Preparation

Principal Investigator's Name:

L. Sirois

Agency and Department:

Canada Centre for Mineral and Energy Technology
Energy, Mines and Resources Canada

Address:

555 Booth Street
Ottawa, Ontario
K1A 0G2

Telephone:

(613) 992-7782

Cooperative Agencies and Investigators: (if applicable)

Canadian Coal Producers

Duration:

Start 1982 - Completion 1986

Approximate Cost: (indicate applicable yearly period)

1982 $250K in-house $150K in contracts

Objectives:

To contribute to the technology of economically upgrading coal to reduce dependence on oil, reduce transportation costs, to improve end-use, and to reduce environmental pollution.

Method:

Part of this project will include:

a) An investigation of the removal of pyrite from coals by high gradient magnetic separation.
b) A preliminary technical evaluation of chemical comminution for releasing fine pyrite from coal.
c) Studies on various physical coal cleaning processes.
d) Install flotation column at Devco. (December 1982)
e) Flotation test program. (December 1983)

Anticipated Results:

Reports will be issued on the work as it progresses.

7.9 Low-NO_x Burner Demonstration Project

Principal Investigator's Name:

G.K. Lee

Agency and Department:

Canada Centre for Mineral and Energy Technology
Energy, Mines and Resources Canada

Address:

555 Booth Street
Ottawa, Ontario
K1A 0G2

Telephone:

(613) 996-4570 Ext. 185

Cooperative Agencies and Investigators: (if applicable)

Duration:

Start 1981 - Completion 1984

Approximate Cost: (indicate applicable yearly period)

1982 $400K

Objectives:

To demonstrate low-NO_x burner at the Armed Forces Base, Gagetown, New Brunswick.

Method:

a) Installation completed. (July 1983)
b) Combustion trials, including addition of limestone (for sulfur capture). (July 1984)

7.10 Evaluation of Low-NO_x Burner for Canadian Coals

Principal Investigator's Name:

W.A. Warfe

Agency and Department:

Energy Sector
Energy, Mines and Resources Canada

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Cooperative Agencies and Investigators: (if applicable)

IEA, EPA, Environment Canada

Duration:

Start 1981 - Completion 1983

Approximate Cost: (indicate applicable yearly period)

1982 $206K

Objectives:

To demonstrate effectiveness of EPA low-NO_x burner for Canadian coals.

Method:

Test firing of two Canadian coals. (July 1983)

7.11 Low NO_x Burner

Objective: The objective of this project is the development, demonstration, documentation, and commercialization of second generation low NO_x burner technology on industrial and utility pulverized-coal-fired boilers. This project has as an objective a NO_x emission of 0.2-0.3 pounds of NO_x per million Btu. This represents a 70-80% reduction from uncontrolled levels and about a 50% reduction from the current NSPS for utility boilers.

Approach: Low-NO_x burner technology has been under development for a number of years and has been successfully developed through bench-scale and prototype testing. The emphasis has been on burner designs applicable to tangentially fired and wall-fired boilers. Two field evaluations utilizing this technology are now well underway; one of these being on a tangentially fired utility boiler and the other being on an industrial boiler. Although the basic development effort is complete, resource reductions have prompted some restructuring of the program to ensure that the technology is as widely applicable as possible. Consequently, additional prototype testing is planned to generalize the results to a broader range of boiler types, sizes, and coal ranks. This approach will ensure that industry has the basis for commercializing the technology without need for future federal funding. The limited resources available in FY's 82 and 83 are necessary to complete both the additional prototype testing and on-going field evaluations.

Rationale: Stationary source emissions of NO_x especially from pulverized coal-fired boilers are projected to increase substantially by the year 2000 and also in their contribution to the total atmospheric NO_x anthropogenic load. Therefore, additional more effective low-cost control technology is essential for new sources of NO_x as well as for retrofit application when acid rain control and reduction is considered as a major national problem. This technology directly addresses both issues, i.e., future more stringent NSPS and acid rain control.

Resources ($1000's):

FY82	FY83
1751	550

Milestones:

- Completion of long-term performance evaluation for industrial boilers; 12/83
- Completion of long-term performance evaluation for utility boilers; 12/84

Contacts: J. Abbott, IERL/RTP, 629-3443
B. Martin, IERL/RTP, 629-7504

7.12 Development and Evaluation of an Advanced NO_x Control Technology for Cyclone-Fired Boilers and Other Retrofit Applications

Objective: To further develop and evaluate the performance of a newly identified NO_x control technique which is suited for cyclone-fired boilers.

Approach: Tests of a new NO_x control combustion modification, which requires the primary zone of a staged combustor to be operated at extremely high temperatures, yielded initial results indicating that NO_x levels as low as 80 ppm (at 0% O_2) can be achieved with reasonable residence times (less than 400 msec) in the primary zone. The high temperatures cause the coal ash to form molten slag, making this technology ideally suited to cyclone boiler applications. A series of bench- and pilot-scale studies will determine why the technology works and how furnace input and design parameters impact emission and steam generation performance. The sulfur capture potential of the molten ash system will be studied to learn the effect of using additives (such as iron or limestone) when burning coal. The majority of the work will be performed at a scale of about 1×10^6 Btu/hr, providing necessary input to design and test a larger prototype system.

Rationale: Cyclone boilers, popular from the 1950's through the early 70's, offered a way to burn problem coals having low ash fusion temperatures and bad slagging characteristics. The coal ash is purposely melted and removed as a molten slag. Unfortunately, the cyclone-fired boiler has typical NO_x emissions greater than 1,000 ppm (some as high as 2,000 ppm). Of the approximately 150 cyclone boilers in the U.S. today, about 90 percent are utility boilers. Although they account for only 9 percent of the steam generation capacity, they contribute about 20 percent of NO_x generated in the utility sector. Unavailability of NO_x control technology, coupled with the utility boiler NSPS, has led to no cyclone boilers being sold since the early 1970's.

This new control technology for cyclone-fired boilers represents about a 90 percent NO_x reduction from uncontrolled levels and should be applicable for both retrofit and for new unit design. By maximizing ash removal, the technology may be used to convert oil-fired boilers to coal firing and to facilitate the use of coal-oil mixtures. If sulfur capture can be effectively incorporated with this NO_x control technique by use of additives, the combined NO_x and SO_x emission reduction offers a strong potential for acid rain control.

Resources ($1000's):

FY81	FY82	FY83	FY84
900	300	0	250

Milestones:

° Initiate contract;	7/82
° Complete construction of pilot facility;	1/83
° Complete evaluation of system parameters on NO_x, SO_x, and particulate control; and	2/84
° Complete final report, including 1 documentation of potential oil backout applications.	0/84

Contacts: W. Steven Lanier, IERL/RTP Project Officer, 629-2432

7.13 Evaluation of In-furnace NO_x Reduction (Reburning)

Objective: The objective is to evaluate the use of in-furnace NO_x reduction (reburning) for potential application on a variety of U.S. stationary combustion sources.

Approach: In the early 1970's fundamental combustion research showed that a secondary fuel injected into combustion product gases at high temperatures will form a reducing atmosphere which will convert NO_x to N_2 and H_2O. Additional air added later at lower temperatures will complete combustion. Results of recent testing in Japan and the U.S. using this concept indicate significant NO_x reductions (of the order of 50 percent). Analyses will be made of the limited data from Japan to assess the applicability of the technique to U.S. designed combustion equipment. Small-scale tests will be made to provide a better understanding of the combustion processes involved with a variety of fuels, and how to optimize their application to practical systems, including utility and industrial boilers and industrial process combustors. In-house tests will be run on commercial-sized combustors firing gas and oil, and contract studies will be run on industrial-sized combustors firing gas, oil and coal. The results will be used to determine different types of combustion equipment on which pilot-scale evaluations could be run. In addition to determining the potential for NO_x reduction, measurements would be made to determine the effect on other combustion-related emissions, equipment performance and product quality (for direct-fired processes). These tests would also provide information on the retrofit potential of reburning.

Rationale: Data already available indicates that in-furnace NO_x reduction has excellent potential. In the U.S., the process has been applied on a limited basis on combined cycle units under EPA Contract 68-02-2144. Also, during preliminary tests run in a bench-scale stoker-fired furnace using coal as the primary fuel, and methane (equivalent to 5% of coal feed) as the secondary fuel, NO_x reductions greater than 40% were achieved. Using methane as both primary and secondary fuel, an NO_x reduction greater than 50% was achieved. These tests were run on existing facilities with no attempt to optimize conditions. Further research and performance tests are needed to optimize the process and determine the full extent of its potential application.

Resources ($1000's):

FY81	FY82	FY83
520	672	0

Milestones:

° Complete draft report on basic combustion tests;	3/82
° Complete survey of prior data and on-going work and recommend applicability of reburning technology in U.S.;	11/82
° Complete draft report describing results of bench-scale tests for selected equipment types (in-house and/or contract); and	6/83
° Complete draft guideline manuals for manufacturers and operators to describe how to apply the reburning process.	12/84 1

Contacts: Robert E. Hall, EIRL/RTP Project Officer, 629-2477

7.14 Heavy Oil/Low-NO_x Burner Development and Field Evaluation

Objective: To support development of a low-NO_x oil burner that can meet the most stringent ambient air quality standards that are now anticipated, with a wide range of liquid fuels.

Approach: Pilot-scale work with a test configuration that maximizes first stage temperature and seeks an optimum fuel-rich stoichiometry has shown that NO_x emissions (at 0% oxygen) can be suppressed to approximately 85 ppmV with a variety of liquid fuels. The heavy oil/low-NO_x burner design developed earlier will be used to fabricate a practical burner for field evaluation in commercial oil field steam generators. Tests are planned, involving a development contractor, a burner manufacturer, and an oil producer's host site to provide comprehensive evaluation on a 50,000-60,000 lb steam/hr unit.

Rationale: Existing commercial burners emit 250-300 ppmV NO_x, a level much too high to allow the use of oil field steamers in Kern County, CA, and some Texas fields. Burner development would permit increased oil production from these fields of from 500 000 to 750 000 barrels per day while still meeting the current California standards. This low-NO_x oil burner technology, while of special significance for use in one-pass oil field steamers, should have wide applicability to the entire range of industrial package boilers and industrial process combustion applications.

Resources ($1000's):

	FY81	FY82	FY83
EPA	0	500	400
DOE	490	0	0

Milestones:

° Award contract for full-scale evaluation of advanced heavy oil burner for enhanced oil recovery;	10/82
° Complete engineering design of prototype burner;	6/82
° Complete field evaluation on field boiler; and	10/82
° Complete draft on user's guidelines manual.	9/83

Contact: W.S. Lanier, IERL/RTP Project Officer, 629-2432

7.15 Operation and Maintenance (O&M) of Existing NO_x Combustion Modification Equipment

Objective: The objective of this project is to evaluate the effect of good operating and maintenance procedures on existing low-NO_x combustion modification equipment, especially low NO_x burners to determine if NO_x can be kept at or below original design conditions.

Approach: The project will include taking existing low-NO_x designed equipment and installing oxygen trim systems with CO monitors to insure continued low-NO_x operation. Both the low-NO_x designs with oxygen trim systems and CO monitors, and low-NO_x designs without these modifications will be regularly monitored over the period of three months to determine the impact of the modifications.

Rationale: A paper study was recently completed on utility boilers equipped with low-NO_x burners in which long-term continuous monitor data (NO and O_2 or CO_2) were analyzed. Of the nine units analyzed, two were equipped with oxygen trim systems and CO monitors. These two were capable of achieving lower NO_x levels, on a consistent basis, than the other seven units. It is very desirable to apply oxygen trim systems with CO monitors to other boilers equipped with low-NO_x burners to determine their effect. If NO_x can be consistently maintained at lower levels, this would be a very cost effective means of NO_x control. The data from this study is needed by OAQPS, EPA Regional Offices, and state agencies.

Resources ($1000's):

FY81	FY82	FY83
43	100	0

Milestones:

° Initiate work assignment;	3/82
° Complete analysis of two boilers using oxygen trim systems;	6/82
° Complete installation of oxygen trim systems and CO monitors;	8/82
° Complete field evaluation; and	11/82
° Complete final draft report;	1/83

Contact: Robert E. Hall, IERL/RTP Project Officer, 629-2477

7.16 Application and Assessment of Combustion Modification Concepts for Coal-Fired Stoker Boilers

Objective: The major objective of this project is to conduct a study of methods for reducing emissions and improving the performance of industrial and commercial coal-fired stoker boilers.

Approach: A two-phase project was specified. Phase I involves the application of modificaions such as overfire air, flue gas recirculation, and two-staged combustion to two spreader stoker boilers. Phase II involves the application of these same techniques to the smaller mass-fed stoker boilers.

Rationale: Coal-fired stoker boilers account for about 5 to 6% of the national stationary source NO_x emissions. In addition, mutagenic and carcinogenic organic compounds are emitted from these sources. Carbonaceous particulate and opacity problems also exist. Combustion modifications have been effective in controlling these emissions in prior field testing work. For example, preliminary tests of combined flue gas recirculation/staged combustion have achieved NO_x reductions of 50-60 percent in a 100,000 lb steam/hr spreader stoker. Assessment for optimized modifications are needed.

Resources ($1000's):

FY81	FY82	FY83
0	231.9	0

Milestones:

° Complete final project report for the first spreader stoker/modification system; and	8/82
° Complete final project report for the second spreader stoker/modification system and the Application Guidelines Document for spreader stokers.	8/83 8/83

Contact: J. H. Wasser, IERL/RTP Project Officer, 629-2476

7.17 Emissions Control by Combustion Modification for Industrial Process Combustion Equipment

Objective: The objective is to develop and apply advanced combustion modification technology to industrial process combustion equipment for emission control and efficiency improvement.

Approach: Results obtained from promising laboratory and subscale tests will be applied to full-scale equipment. In addition to monitoring emissions during combustion modification tests, equipment efficiency and quality of the product produced will be evaluated. Combustion modification technology found to be successful for boilers will be adapted as necessary, and will be evaluated on selected types of industrial process equipment.

Rationale: Much of the combustion modification technology previously developed to control emissions from industrial and utility boilers is directly applicable to other stationary combustion equipment. Since NO_x emissions are very high from petroleum process heaters, cement kilns, steel furnaces, and glass furnaces, it is desirable to determine the effect of combustion modification for NO_x control from these sources. Preliminary tests using forced-draft staged air lances on petroleum refinery heaters have resulted in 71% NO_x reductions for gas-fired units, and 53% NO_x reductions for oil-fired units, while providing a 5% fuel savings.

Resources ($1000's):

FY81	FY82	FY83
340	510	0

Milestones:

° Complete NO_x control assessment for refinery process heaters;	3/83
° Complete NO_x control assessment for steel furnaces;	6/83
° Complete NO_x control assessment for cement kilns; and	12/83
° Complete NO_x control assessment for glass furnaces.	3/84

Contacts: Robert E. Hall, IERL/RTP Project Officer, 629-2477

7.18 Fundamental Combustion Research Program

Objective: To support low-emission combustion modification technology and low-NO_x burner development with well-directed research of a fundamental nature. The chemical, physical, and aerodynamical phenomena important in the processing of fuel-bound nitrogen to NO_x and in the formation of particulate and organic species especially polycylic organic matter, will be established.

Approach: The program management structure includes a master contract with the prime contractor and a number of sub-contracts, of varying duration, on specific tasks. Presently, the program is split nearly evenly between prime contract work and work by the sub-contractors. Research grants and cooperative agreements are utilized as appropriate. In addition, an in-house R & D effort augments the various contractual studies.

Rationale: The ultimate goal of the program is to provide a well-substantiated means of estimating the lowest achievable NO_x emissions from current and future combustors. Models are required also for POM generation during combustion processes to guide effective control technology development for these emissions as well.

Resources ($1000's):

FY81	FY82	FY83	FY84
1500	250	100	150

Milestones:

° Special report on continuous monitoring of hydrocarbons as a measure of destruction and removal efficiency by hazardous waste incinerators;	12/81
° Special project report on chemical kinetic parameters controlling NO_x reduction by reburning;	4/82
° Special report on drop-size distribution from heavy oil atomizers for application to low-NO_x EOR burner systems; and	12/82
° Complete initial study of advanced aerodynamic removal techniques for coal ash from cyclone type burners.	12/82

Contacts: W.S. Lanier, IERL/RTP Project Officer, 629-2432

7.19 Technology Transfer through Joint EPA/EPRI Symposium on Stationary Combustion NO_x Control

Objective: The objective is to plan, organize, and hold a national symposium addressing the recent advances in NO_x control technologies for stationary combustion sources, and to publish the proceedings containing the technical papers which are presented.

Approach: Plans will be developed to sponsor a national symposium (including interested international attendees) in coordination with the Electric Power Research Institute (EPRI). A contractor will be selected to plan and operate the symposium and to prepare the proceedings for publication, as a cooperative effort between the Special Projects Office and the Combustion Research Branch within IERL/RTP.

Rationale: This symposium provides a unique opportunity for transferring technical information on advances in NO_x combustion modification and FGT methods and for exchange of pertinent information between the utility/industrial sector, EPA and related organizations regarding future problems and control strategies.

Resources ($1000s):

FY81	FY82	FY83
0	20	0

Milestones:

- Hold joint symposium (with EPRI) on stationary combustion NO_x control; and — 11/82
- Publish proceedings. — 2/83

Contacts: Robert E. Hall, IERL/RTP Project Officer 629-2477
Dennis C. Drehmel, IERL/RTP Project Officer, 629-7505

7.20 Limestone Injection Multistage Burner (LIMB)

Objective: The objective of this program is the development, generalization and documentation of the basis for commercialization of LIMB for simultaneous control of SO_x and NO_x for pulverized coal fired boilers. The program goal for retrofit is 50 to 70% SO_x removal and 0.2 to 0.4 lbs. NO_x per 10^6 Btu to provide a cost effective approach for control of acid rain. The research goal is 90% reduction in SO_x and 0.2 to 3 lbs. NO_x per 10^6 Btu for optimized new systems.

Approach: Recent R & D results in the U.S. and Germany have shown the potential for SO_x control by the injection of alkali sorbent through delayed mixing combustion systems, which also control NO_x. A coordinated R & D program has been implemented to address the major technical aspects of the technology. It includes bench- and pilot-scale experimentation to establish the emission control potential as a function of process characteristics and a system study to document the approach to commercialization by the private sector. The bench-scale work will establish: 1) critical chemical processes; and 2) the effect of combustion environment and operating variables on NO_x control and SO_x capture efficiency. The pilot-scale studies include experimentation on commercial and prototype low-NO_x coal burners for new and retrofit systems for both wall- and tangentially-fired boilers. The system study defines solutions to application problems and provides the design and cost basis for commercialization of the technology. In view of budget reductions, field evaluation of the technology has been eliminated and the output of this study will provide the technical basis for private sector demonstration of LIMB, which will be necessary for widespread application. In addition, much of the bench-scale research will be performed in-house at IERL-RTP.

Rationale: Several analyses of the causes of acid rain indicate that the major precursors from pulverized coal-fired steam generators are SO_x and NO_x. To retrofit conventional SO_x control on the existing boiler population would impose a large economic burden. Therefore, a cost-effective retrofit technology is required. The LIMB technology is projected to give SO_x reductions of 50 to 70% at a cost of $40/kW and NO_x levels in the range of 0.2 to 0.4 lb/10^6 Btu on retrofit systems. In addition, the R & D studies will also identify the optimum approach for SO_x and NO_x control applicable to new sources in support of NSPS.

Budget ($1000's):

FY81	FY82	FY83
870	3252.9	2500

Milestones:

° Complete initial system study;	3/82
° Initial guidance for commercialization;	3/84
° Complete pilot testing; and	3/85
° Final design criteria for commercialization.	9/85

Contacts: J. Abbott, IERL/RTP, Project Officer, 629-3443
B. Martin, IERL/RTP, Project Officer, 629-7504

7.21 FLUIDIZED-BED COMBUSTION MECHANISMS

Principal Investigator's Name:

F.D. Friedrich

Agency and Department:

Canada Centre for Mineral and Energy Technology
Energy, Mines and Resources Canada

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K1A 0G1

Telephone:

(613) 996-4570 Ext. 185

Cooperative agencies and investigators: (if applicable)

Queen's University

Duration:

Start 1979 - Completion 1984

Approximate Cost: (indicate applicable yearly period)

1982 $125K in contracts

Objectives:

To elucidate the mechanism in the in-situ sulfur capture during combustion, using additives to the coal feed and changes in combustion parameters.

Method:

a) Trials with two coals including one with limestone. (April 1982)
b) Rig modifications. (July 1982)

Anticipated Results:

An in-depth study of the chemistry of sulfur capture and of SO_2 and NO_x emissions in fluidized-bed combustion.

7.22 Pilot-Scale Fluidized Bed Combustion (FBC)

Principal Investigator's Name:

F.D. Friedrich

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Energy, Mines and Resources Canada

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Cooperative agencies and investigators: (if applicable)

Duration:

Start 1976 - Completion 1984

Approximate Cost: (indicate applicable yearly period)

1982 $250K in-house, $200K in contracts.

Objectives:

To develop and extrapolate fluidized-bed technology to burn low-grade Canadian coals and coal rejects in steam generating and process heat applications under acceptable environmental conditions.

Method:

a) Preliminary tests with feasibility of temperature diagnostics. (October 1982)
b) Characterisations of Canadian limestone as sulfur receptors. (March 1983)
c) Second phase of coal-feeder development. (September 1983)
d) Liaise with contracting parties under International Energy Agency agreement for FBC data exchange. (April 1984)

(N.B. All burn trials include monitoring of SO_2 and NO_x. The effect of limestone addition will be determined on high sulfur coals.)

7.23 FBC Demonstration Program, Summerside, Prince Edward Island

Principal Investigator's Name:

F.D. Friedrich

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Cooperative agencies and investigators: (if applicable)

Department of National Defence
Dominion Bridge
Foster Wheeler

Duration:

Start 1976 - Completion 1984 Total Cost $13M.

Approximate Cost: (indicate applicable yearly period)

1982 $8M in contracts

Objectives:

To design and demonstrate the feasibility of FBC technology for steam raising using Maritime coals and wood at CFB Summerside.

Method:

a) Completion and commissioning of first boiler. (September 1982)
b) Demonstration trials completed. (April 1984)
c) Second boiler specification and installation. (February 1983)

Anticipated Results:

A fluidized-bed unit capable of burning high sulfur coal with limestone addition to produce low NO_x and SO_x emissions.

7.24 Assessment of Dry, Semi-Dry and other technologies for application to Canadian Utilities

Principal Investigator's Name:

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G. Lee, CANMET (613) 996-4570

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Canada Centre for Mineral and Energy Technology
Energy, Mines and Resources Canada

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Telephone:

See Above

Cooperative agencies and investigators: (if applicable)

Duration:

Start 1981 - Completion 1983

Approximate Cost: (indicate applicable yearly period)

FY 81	FY 82	FY 83
$100K	$900K	to be determined

Objectives:

To identify technologies applicable to containment of sulfur and nitrogen oxides emissions and associated land and water pollution arising from fossil fuel generation and, advise the Canadian Electrical Association Generation R & D Committee on research and development requirements in this area.

Method:

The viability of the various technologies applicable to control of emissions from Canadian coals utilized by Canadian utilities will be assessed. Two areas of thrust will be considered; (i) research and development, and (ii) methodology developed to determine a cost effective demonstration process for a Maritime utility.

Anticipated Results:

An informed basis must be developed to enable an appropriate evaluation of the cost effectiveness of the technology. Unique processes requiring research and development must be encouraged.

7.25 Evaluation of Heat-Exchange Materials for Utility Applications of FBC

Principal Investigator's Name:

Dr. R. Brigham

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Energy, Mines and Resources Canada

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(613) 995-4590

Cooperative agencies and investigators: (if applicable)

Nova Scotia Power Corporation
(project manager)

Duration:

Start 1982 - Completion 1985

Approximate Cost: (indicate applicable yearly period)

1982 $4M

Objectives:

To evaluate heat-exchange materials for use in FBC units designed for electrical power generation, using a 1 m^2 test combustor.

Method:

a) Test program comprising 10 x 1000 hour operation underway. (April 1983)
b) Test program completion. (March 1985)

Anticipated Results:

Delineation of required metallurgical characteristics of heat-exchange materials for utility FBC applications.

7.26 Bitumen/Heavy Oil and Processed Product Characterization and End-Use Assessment

Principal Investigators' Name:

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Cooperative agencies and investigators: (if applicable)

Petro-Canada and various engineering associates.

Duration:

Start 1979 - Completion 1982

Approximate Cost: (indicate applicable yearly period)

1982 $250K

Objectives:

Involved within this general activity are several projects which include investigations on chemical composition and removal of sulfur and nitrogen compounds from bitumen/heavy oils as part of the overall activity.

Method:

a) Report on the effect of hydrocracking on sulfur-type distribution.
b) Report on catalytic desulfurization of pitch.
c) Reports on the use of sorbents for the removal of nitrogenous compounds from hydrocracked bitumen and heavy oils.

7.27 Assessment of NO_x and Combined SO_x/NO_x Control by FGT Technology

Objective: Provide an informed basis to evaluate FGT technology for 70-90% control of NO_x and SO_x emissions from stationary combustion sources.

Approach: Through technical and economic evaluations of post-combustion NO_x and combined SO_x/NO_x processes, the viability of the technology will be assessed. Emphasis will be placed on results from the pilot plant testing in the U.S. and on results from commercially operating, full-scale units in Japan. In parallel with these technical assessment activities, economic studies to determine the cost of applying the technology to coal-fired utility boilers in the U.S. will be undertaken. These technical and economic assessment activities will enable industry, vendor, and regulatory personnel to determine the cost effectiveness and feasibility of utilizing FGT technology for highly efficient (70-90%) control of NO_x and SO_x emissions.

Rationale: There are a number of environmental issues--such as acid rain, prevention of significant deterioration (PSD), non-attainment, visibility, NSPS, and the short-term NAAQS--confronting both industry and government which may require consideration of highly efficient control of NO_x and SO_x emissions. The only technology currently available to achieve 70-90% removal efficiencies is FGT technology. Therefore, an informed basis must be developed to enable an appropriate evaluation of the cost effectiveness of the technology.

Resources ($1000's):

FY81	FY82	FY83
3	131.2	0

Milestones:

° Complete report on the Pilot Plant Evaluation of the Hitachi-Zosen NO_x FGT Process;	2/82
° Complete report on the Independent Evaluation of the Hitachi-Zosen NO_x FGT Process;	2/82

° Complete report on the Pilot Plant evaluation of the Shell/UOP Simultaneous NO/ SO_x Process;	6/82
° Complete report on the Status of NO_x Control Technology in Japan;	9/82
° Complete report on the Status of SO_x Control Technology in Japan; and	9/82
° Complete definitive economic assessment of NO_x and SO_x flue gas treatment technology.	12/82

Contacts: D. Mobley, IERL-RTP, 629-2578

7.28 Assessment of an Electronic Beam Precharger for High Resistivity Ash Removal

Objective: Information will be collected concerning technical processes for high resistivity ash removal to enable the private sector to develop appropriate technology for use of high resistivity ash coal. Reduction of certain ashes which are known to catalyze SO_2 to SO_4 will have the added benefit of reducing acie rain levels.

Approach: The primary thrust of this effort is the advancement of emissions control technology, supporting private sector efforts towards increased coal utilization. DOE does not conduct any R & D aimed specifically at acid rain abatement; however, this project is important to the National Acid Rain Assessment Program because of the secondary (or indirect) benefits - in acid rain reduction - which result from improvement in emissions control. The project is a labe experiment designed to gain data on capture of fly ash using E-Beams as initial ionizers.

Resources ($1000's):

FY81	FY82	FY83
0	100	100

Contact: E. Trexler, DOE-FE, 223-4743