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AN AIR EMISSION GUIDELINE FOR NEW COAL GENERATING STATIONS WHERE FEDERAL FUNDING IS INVOLVED

ATLANTIC REGION REPORT
July 1980

AIR POLLUTION AND ACID PRECIPITATION

by ROD W. SHAW

ABSTRACT

The urgent need to replace oil fired electric generating stations in the Atlantic region, together with international as well as national concerns about "acid rain" make the setting of an air emissions control guideline for new coal fired electric generating stations mandatory.

Five papers are enclosed with this report which discuss different aspects of this problem. A guideline similar to that selected in the United States for Noncontinental areas (U. S. Env. Protection Agency, Fed. Register Vol. 44, No. 113, June 1979) is recommended, i.e.: SO_2 emissions to the atmosphere are to be limited to 1.20 lb/million BTU; particulate limits are 0.03 lb/million BTU; and NO_x limits are 0.50 lb/million BTU. These limits should be applied for all planned generating stations, which receive federal financial assistance.

The setting of these emission guidelines now may strengthen Canada's position in international discussions. They will demonstrate federal leadership in interprovincial air pollution standards and they will provide an environmental guideline in the energy planning and development presently underway in Provincial utilities.

The consequences of issuing these guidelines are:

1) That a start will have been made on the control of future air emissions.

2) Provincial electric utilities may make greater use of hydro, nuclear, and natural gas, as well as conservation programs which are in the long run more economic than coal fired electric generation, as well as being more environmentally attractive; greater co-operation between utilities will develop.

3) Coal, if not used for thermal power generation will be available for metallurgical, petrochemical and other industrial uses over a longer period of time, thus presenting other social and economic benefits.

INTRODUCTION

The purpose of this report is to recommend that an air emission guideline be set now for those new coal-fired thermal electric generation stations in Atlantic Canada which receive any federal financial assistance, or which use thermal coal under contracts from the federal crown corporation, DEVCO. The consequences of a proposed guideline are discussed.

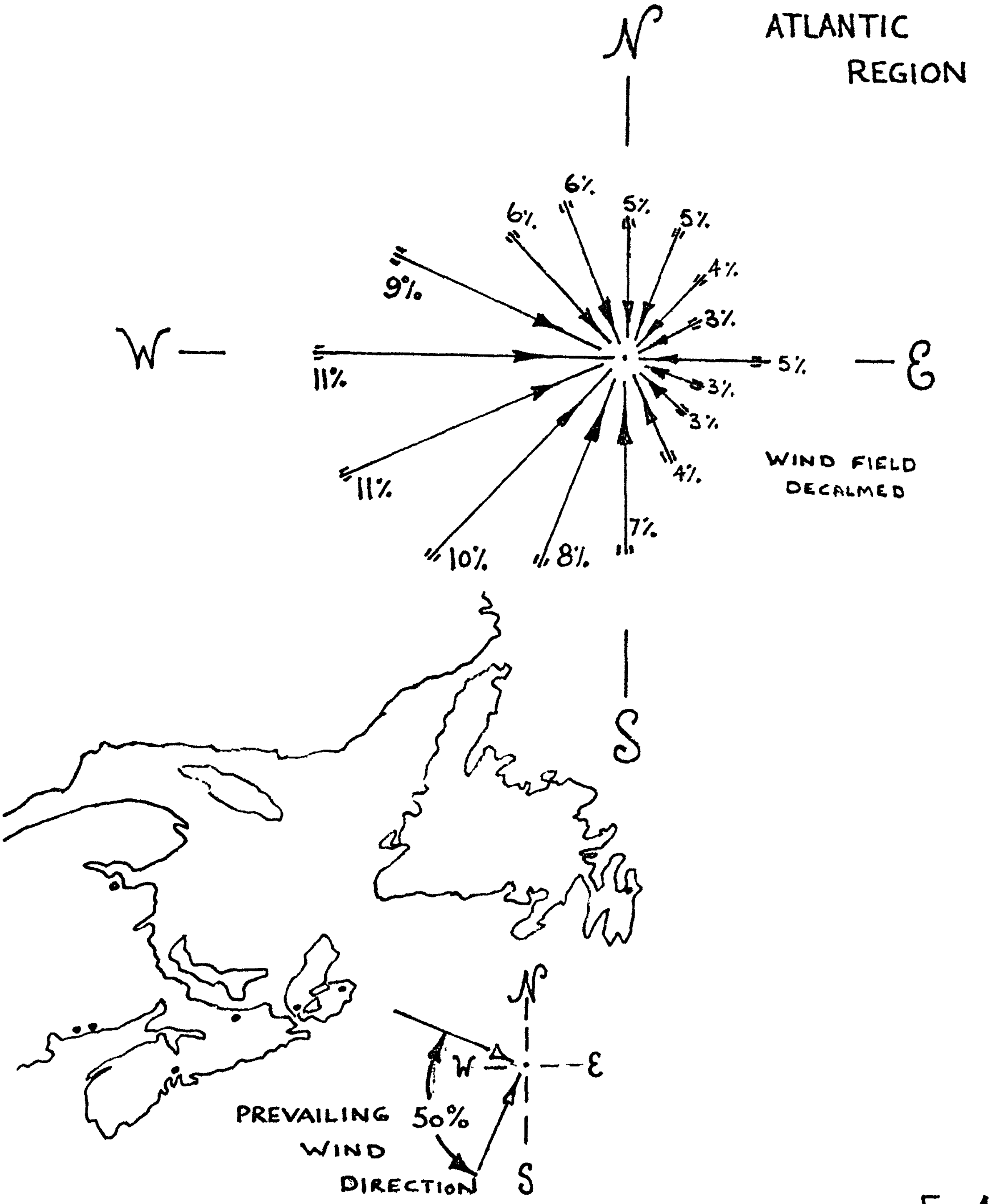
Five separate papers are included with this report which provide more detailed background information.

The papers are as follows:

1. Air Pollution and Acid Precipitation;
   Rod W. Shaw.
2. Potential Aquatic Effects of Increased Acid Deposition Due to Expanded Use of Coal for Power Generation in the Atlantic Region;
   J. Wiltshire and J. Machell.
3. Changes in SO_2 Emissions and Sulphur Depositions in the Atlantic Region from an Expanded Use in Coal for Power Generation;
   D. A. Lord
4. Design Criteria, Treatment Technology and Costs;
   K. Hamilton
5. Alternate Coal Use;
   J. K. Day

The report summarizes the present thermal electric energy situation in the Region and points out that, as conversions of oil-fired generation to alternate systems are planned and underway, it is essential that an emission control guideline be established, particularly, as Federal money may be used to assist in the conversion process. The reasons for selecting a guideline are outlined, as well as the consequences.

WIND ROSE AND PREVAILING WIND QUADRANT



PRESENT STATUS

There are three essential factors which influence the coal thermal energy problem in the Atlantic region. The first is the prevailing wind. The second is the present thermal power generation system and the third is the quality of the coal in the mines of Nova Scotia and New Brunswick. These three factors are summarized.

1) The prevailing winds in the Atlantic region are from the west and the south. Figure 1, which is a wind rose based on data provided by the Atmospheric Environment Service, illustrates the prevailing wind patterns. These winds tend to transport airborne pollutants to the region from southern Canada and from industrial areas of the north-eastern United States. The winds also carry some pollutants generated in this region and elsewhere to the Atlantic Ocean. The paper by Shaw (1) indicates that "the present rate of deposition of atmospheric acid, and the potential effects upon fresh water and forest soils is a matter of great concern". The paper by Wiltshire and Machell (2) concludes that "the watersheds over much of the Atlantic region provide little or no buffering capacity to surface waters, with the result that these surface waters are highly susceptible to the effects of increased acid loading. There is evidence that many lakes and rivers, particularly in Nova Scotia, have undergone substantial pH declines during the past 20 to 30 years, and many of these freshwaters are currently at pH levels where the survival of sensitive species is either not possible or is endangered".

2) The oil and coal thermal electric generation rated capacities are as follows:

PROVINCE	MW OIL	MW COAL	MW COAL/OIL
New Brunswick	1508	264	
Nova Scotia	730	470	49
P.E.I.	50		
Newfoundland	450		

A more extensive list of thermal power sites is listed in Table 1 and Figure 2 shows the locations of large units such as Coleson Cove (N.B.) and Tufts Cove (N.S.). A major addition to the New Brunswick system will be the completion late in 1981 or early in 1982 of the Lepreau 1 nuclear reactor.

It has been known for some time that major conversions from oil to alternate power generation must be carried on; this was confirmed again during the past few days at the international level in Venice. The "off-oil" program means more nuclear electric generation or more coal electric generation where hydro power is unavailable.

3) A major problem with use of coals from mines in the Cape Breton area and from Minto in New Brunswick is the high sulphur content found in many seams.

Sulphur contents in some seams and mines in Cape Breton are as follows:

	Sulphur Range %	Sulphur Average %
Harbour Seam		
No. 26	0.7-2.0	1.4
Lingan	1.0-3.0	1.8
Donkin	2.6-6.1	4.3
Phalen Seam		
Lingan-No. 26	1.5-4.0	
Hub Seam		
Donkin	4.4-6.4	
Prince	2.0-6.05	5.2
Lloyd Cove Seam		
Donkin	2.6-5.8	3.9

At Minto in New Brunswick the sulphur contents are even greater, ranging from about 5.5-8.0%.

Most of these coals are far higher in sulphur content than coals from many of the mines in Western Canada.

The situation therefore is one where there are prevailing winds bringing some acid precipitation to the region, there are utilities heavily committed to oilfired electric generation which must convert to alternate generation and there are coal mines having a high sulphur content of coal.

DEVELOPMENT PLANS

There are a number of electric energy generation options in the region which can be developed within this decade. These include:

a) Further hydroelectric development on the Lower Churchill River, the Saint John River and later, Fundy Tidal Power;

b) Nuclear Power from CANDU reactors;

c) Coal from Cape Breton with properly installed treatment facilities and even coal from western Canada;

d) Natural gas from off-shore;

e) Effective conservation will reduce demands at peaks.

Each of these have their own economic and environmental advantages and disadvantages which are known to planners managing utilities. It should be realized that coal development is not necessarily the most economic source of electric energy, though it is a source favoured in Nova Scotia. Figure 3, taken from an information document released by the New Brunswick Electric Power Commission (Dec. 1979) illustrates estimated comparative energy costs of oil-coal-nuclear power where the coal is excavated by open pit mining in Minto, N. B. There are indications to suggest that, comparatively, Cape Breton coal costs would not be any more economic than Minto coals from thermal power generation. In order to make a proper economic as well as an environmental comparison, information is provided on the consequences of going ahead with development of local coals with and without treatment together with the costs of treatment in new plants. The paper by Lord (3) reviews the changes in SO_2 emissions which may occur under expanded coal fired generation in the region without treatment and with treatment for sulphur. The paper by Hamilton (4) reviews design criteria and treatment costs for plants in the region.

It is apparent from the above studies that expanded coal use without SO_2 emission control will turn the region into a net exporter of sulphur causing significant interprovincial and, under certain wind conditions, international air pollution problems.

Comparisons have been made by the authors of effects and costs if emissions are controlled to 1.2 lbs. $SO_2/10^6$BTU or 1.6 lbs. $SO_2/10^6$BTU. Proper treatment will raise the cost for power about 4-5 mills/kwhr. It is apparent from their papers that a guideline for emission controls is mandatory in order to assist in the power planning and development decisions which are being made now.

AN AIR EMISSION CONTROL GUIDELINE

There are four reasons for setting a control guideline now. The first is for international reasons, the second is for interprovincial reasons, the third is because federal funds may be involved and they must be properly spent locally; the fourth is a matter of timing.

The reasons are discussed briefly:

1) International Reasons.

There are many precedents and principles in transboundary pollution cases and there exists a similarity between trans-boundary air pollution and transboundary river pollution. The classic case in air pollution in North America is the *Trail Smelter* case when the United States government acted on behalf of farmers and residents in part of Washington State. In the Trail Smelter Arbitration Decision (United States v. Canada) damages were awarded to the United States and an injunction was granted restraining the Trail Smelter from continuing its unlawful practices. This case is particularly referred to here because there is an element of hypocrisy in some media reports about air pollution from the United States into Canada. The old saying about "the pot calling the kettle black" may be applied to Canada if we do not set our house in order.

There are several diplomatic means of negotiating transboundary disputes between Canada and the United States, including especially the International Joint Commission created under Article VII of the 1909 Boundary Waters Treaty.

An ancient legal doctrine which can be applied to many injurious activities carried out in one state which may do harm to neighbouring states is embraced in the phrase *sic utere tuo ut non alienum laedas* - "thus thou shalt use thine own in order not to injure others." This maxim was first suggested in 1688 and remained dormant in international law until very recent times where it has been quoted as a guiding principle in several cases. There is inevitably a certain vagueness about a legal maxim of this kind because it does, by implication, beg the question of reasonable behaviour by both sides. Fortunately in North America we have two nations with very similar cultural, legal and economic philosophies, so in broad generalities, we are able to agree on reasonable behaviour. That is not to say that on technical details we may always agree, because either party may have local economic or political reasons for being especially intractable over a period of time, and may seek to prolong negotiations as much as possible.

Reasonableness between Canada and the United States with respect to air pollution can first be compared by an examination of the comparable air pollution control regulations and the effectiveness of their enforcement. In this respect, it would appear that the United States is ahead of Canada and is behaving more reasonably in that it has a formal set of performance standards for electric utility steam generating units. (U.S. Env. Protection Agency, Federal Register, Vol. 44, No. 113, June 11, 1979, Rules & Regulations, See Appendix 1). The effectiveness with which these regulations are enforced has not been checked from the Atlantic region as that is primarily an Ottawa responsibility. However, the very fact that such regulations exist while Canada has no comparable regulations suggests that Canada is not in a position to complain to the United States about transboundary air pollution from coal-fired electric generators until there are comparable regulations here. The United States regulations are strict and apply to a wide range of fuel types.

Bearing in mind that the prevailing winds into the Atlantic region are from the southwest and that at present the Atlantic Provinces are, in total, receivers of sulphur emissions, it would seem that a reasonable approach would be to use that portion of the U.S. regulations which apply to Noncontinental areas as a standard to work on in Canada as a start for all new coal-fired generating stations. This would permit a greater use of some western coals in the east; but it is apparent that all coals found in the Maritimes will have to be treated.

2) Interprovincial Reasons.

Here the Federal government is the arbitrator between Provinces and the legal doctrine which applies in international law must also apply interprovincially. It is apparent that Newfoundland can be the receiver of effluents from the Maritime Provinces and there has already been some correspondence about this at the Ministerial level. There would appear to be a need for the Federal government to use its power and responsibility to declare a guideline.

3) Local Expenditure of Federal Funds.

It is probable that incentives may be provided to the Provinces in order to hasten the "off-oil" program and to reduce the burden of the immense oil import compensation payments. If this is done then Environment Canada should see that those federal funds are invested in an environmentally suitable manner. Furthermore, at present the Federal government has DEVCO, a crown company, operating in Cape Breton with long term contracts to sell coal for thermal power generation to the Nova Scotia Power Corporation. Does a crown company have the responsibility to see that its product is used in an environmentally satisfactory manner? This is a question for the Minister and Cabinet to decide; but if the answer is "yes" then Environment Canada should be negotiating with both DEVCO and the Nova Scotia Power Commission to see that air emissions are controlled.

4) Timing.

Engineering plans are being made, future power sales are being negotiated, financing is being arranged, all for new electric power generation projects. The cost of hydro, nuclear and coal generating sites and the costs of transmission interconnections are continually being reviewed as each decision is arrived at. An emission control standard effects these costs and it is unreasonable to the utilities to delay their decision while awaiting a ruling from Environment Canada. If a ruling is delayed, then follow-up action and various remedial treatment facilities will also be delayed. Therefore, if "acid rain" is deemed a problem by Environment Canada it is appropriate that the Department act now to provide a guideline on emission controls.

CONSEQUENCES AND ALTERNATES

The consequences of issuing a control guideline may be briefly summarized in five sections:

1. The guideline where federal funds are being used will be a clear signal to Provinces, the United States and the utilities as to the position of the Federal Government. It will benefit the future quality of the air.

2. The decision makers in utilities and Provincial Governments as well as Federal Departments, such as EM & R, DREE and Finance will know one more factor in their energy financing, which effects electric power generation costs.

3. The cost of future power generation at some proposed plants will rise by the order of 4-5 mills kwh. Coal from the west could be shipped by sea to certain eastern power sites for mixing with local coals.

4. The Atlantic Provinces, particularly the three Maritime Provinces may see the sense of making greater efforts to pool their future electric power planning instead of striving for energy self sufficiency as is the case in Nova Scotia. Alternate uses of energy development and greater conservation programs will be more attractive. It would seem that nuclear power is at present comparable to coal for baseload power generation and, as coal costs rise, it will be far cheaper than coal. Another CANDU reactor for baseload power generation is an attractive economic possibility as well being more attractive environmentally. (An earlier memorandum to the Department has recommended a charge of one mill/kwh to be made to fund nuclear waste disposal). A regional mix of hydro, nuclear, coal and later, tidal and other renewable generation schemes are all good possibilities. Much of the "energy crisis" in the region is a crisis of inadequate co-operation.

5. Future uses of Cape Breton coal as a resource will not be prevented. The coal may, in the long run, be used more profitably. DEVCO are presently trying to work out a development strategy for coal. Their report, "Towards a Development Strategy for Coal Mining in Cape Breton, DREE Confidential Report, April 1980" is evidence of this.

   The last paper with this report by J. K. Day discusses the technology and alternate uses for coal. It is apparent that other industrial uses may be developed at a profit and with a higher employment benefit than using sulphur coal for thermal power. The most recent edition of the Engineering Journal of Canada (Vol:63, No. 3, June 1980) also devotes articles to coal liquefaction and alternate uses. Research on these alternates should continue.

CONCLUSION

There should be no further delay in issuing an air control emission guideline for new thermal electric generation stations where federal funds are involved. The guideline should be similar to the U.S. Guideline for offshore utilities and should call for an SO_2 limit of 1.2 lbs/10^6BTU. Letters should be sent at the Ministerial level to the appropriate Federal departments and Provincial governments advising them of this.

In the long run, there are environmental benefits to be obtained by setting an emission control limit and the Department of Environment has the professional responsibility to set this limit as early as possible.

The setting of a limit does not restrict eastern electric energy development, for in reality, much of the "energy crisis" in Canada is a crisis of inadequate co-operation and inadequate planning. There is plenty of "energy wealth". There is a reluctance to share this wealth and to co-operate in it's development.

THERMAL GENERATION STATIONS

ATLANTIC REGION

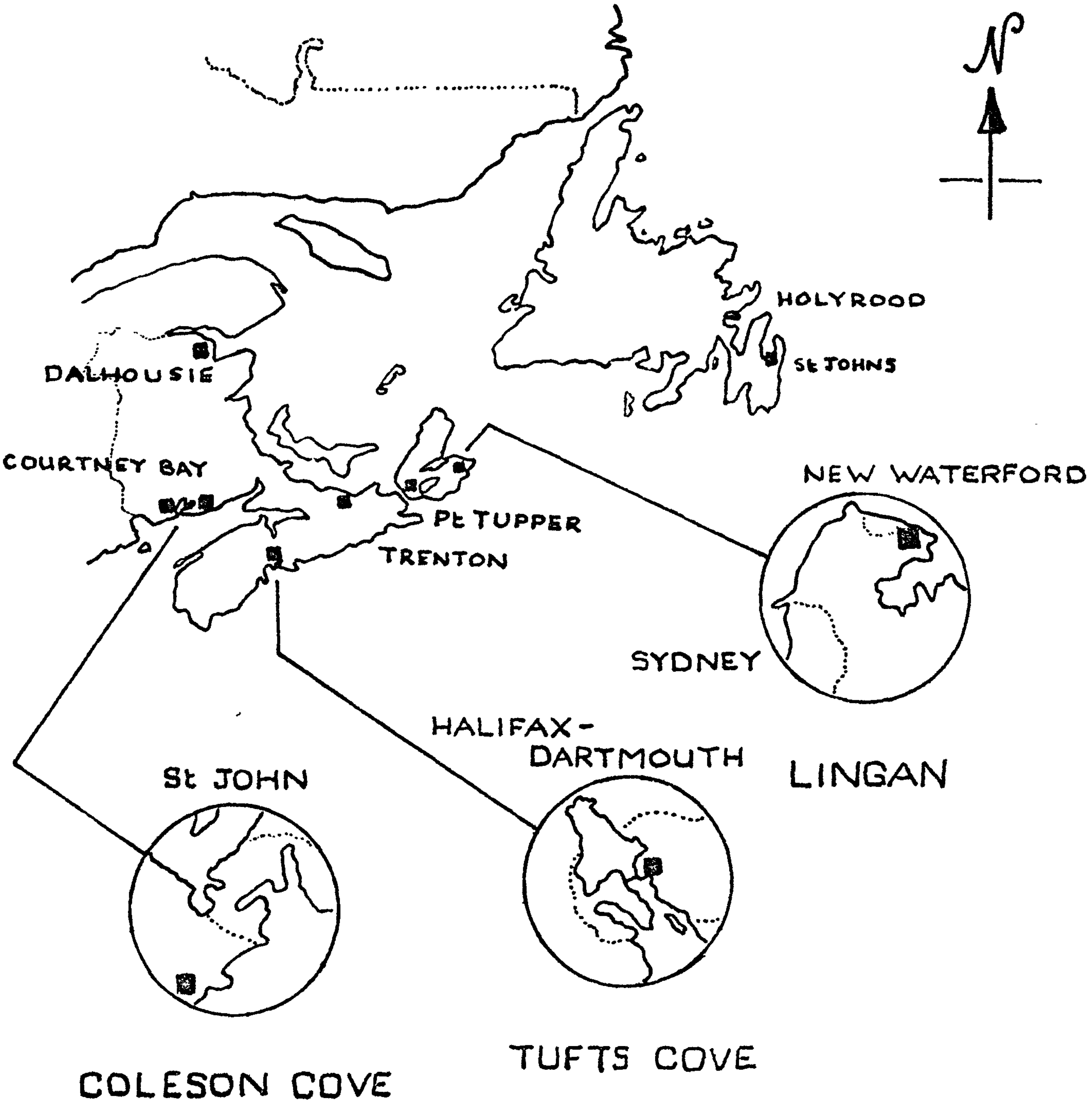
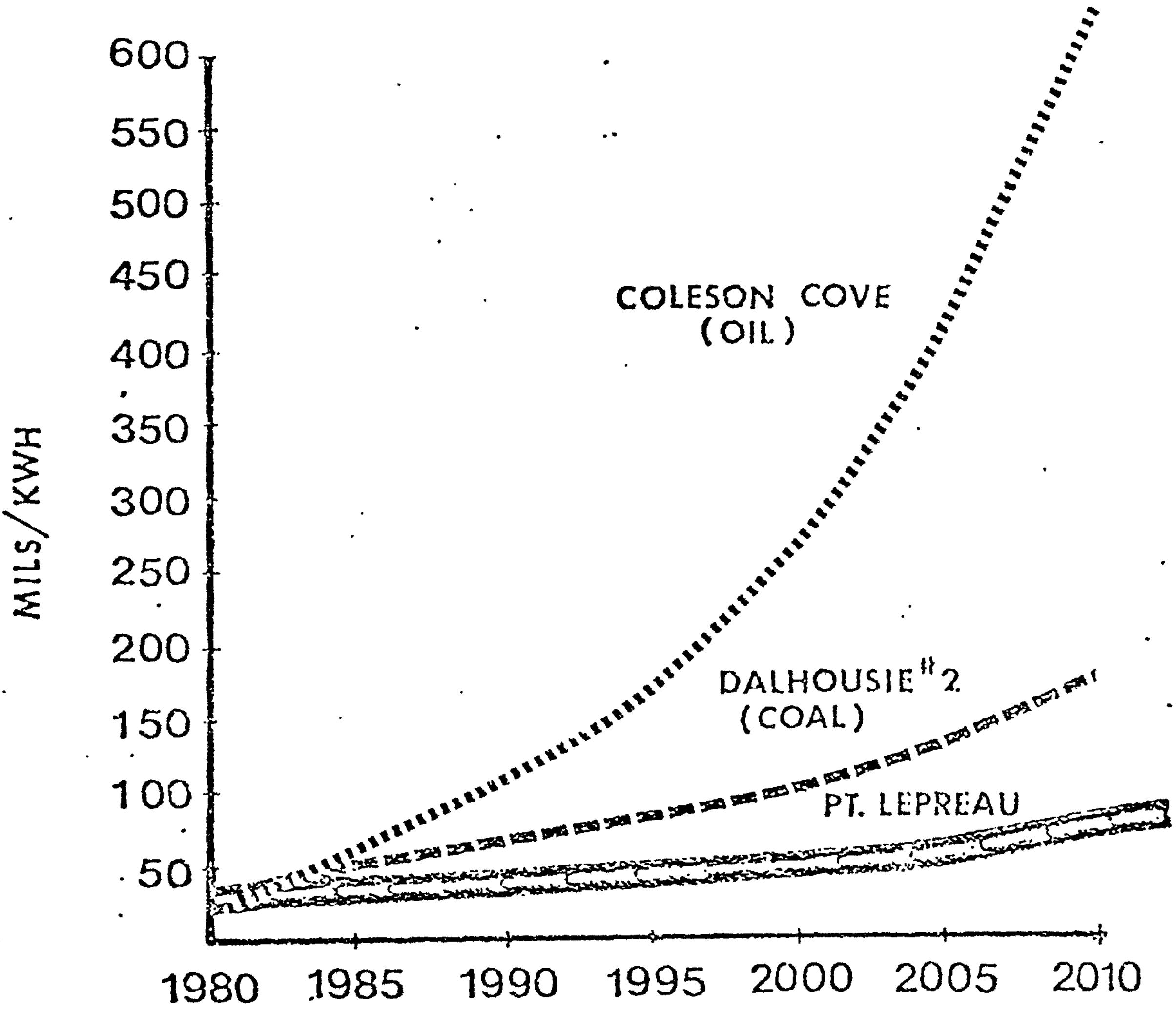


Fig 2

FIGURE 3

RELATIVE COST
OIL/COAL/NUCLEAR



PURPOSE:	To illustrate the costs of producing energy from different sources within New Brunswick.
NOTES:	Pt. Lepreau curve is calculated over a range of completion costs (represented by the shaded area) ranging from \$895 million to \$1100 million to demonstrate the effect of project cost on the cost of energy from that station. Nuclear fuel is escalated at 5%/year to 1990 and 7% thereafter.
	Dalhousie #2 is calculated at \$135 million with fuel escalated at 7%/year.
	Coleson Cove is calculated at \$244 million with fuel escalated at \$4.00 per barrel to 1985 and 10% per year thereafter.

TABLE 1

OIL AND COAL GENERATING STATIONS

STATION	NO. OF UNITS MW	FUEL
New Brunswick		
Coleson Cove	3 x 372	OIL
Dalhousie	1 x 112	OIL
	1 x 200	COAL (Minto)
Courtenay Bay	1 x 14	OIL
	1 x 54	OIL
	2 x 106	OIL
Grand Lake	1 x 64	COAL (Minto)
	1 x 200 (1990?)	
Nova Scotia		
Lingan 1 & 2	2 x 150	COAL (Cape Breton)
Glace Bay	1 x 15	COAL/OIL
	2 x 17	COAL/Oil
Point Tupper	1 x 65	OIL
	1 x 150	OIL
Tufts Cove	2 x 100	OIL
	1 x 150	OIL
Trenton	1 x 20	COAL (Cape Breton)
	1 x 150	COAL (Cape Breton)
Water Street	1 x 165	OIL
Prince Edward Island		
Maritime Electric	1 x 10	OIL
	2 x 20	OIL
Newfoundland		
Holyrood	3 x 150	OIL
	1 x 150 (1984)	

APPENDIX

federal register

Monday
June 11, 1979

Part II

Environmental Protection Agency

New Stationary Sources Performance Standards; Electric Utility Steam Generating Units

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1240-7]

New Stationary Sources Performance Standards; Electric Utility Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: These standards of performance limit emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x) from new, modified, and reconstructed electric utility steam generating units capable of combusting more than 73 megawatts (MW) heat input (250 million Btu/hour) of fossil fuel. A new reference method for determining continuous compliance with SO_2 and NO_x standards is also established. The Clean Air Act Amendments of 1977 require EPA to revise the current standards of performance for fossil-fuel-fired stationary sources. The intended effect of this regulation is to require new, modified, and reconstructed electric utility steam generating units to use the best demonstrated technological system of continuous emission reduction and to satisfy the requirements of the Clean Air Act Amendments of 1977.

DATES: The effective date of this regulation is June 11, 1979.

ADDRESSES: A Background Information Document (BID: EPA 450/3-79-021) has been prepared for the final standard. Copies of the BID may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711, telephone 919-541-2777. In addition, a copy is available for inspection in the Office of Public Affairs in each Regional Office, and in EPA's Central Docket Section in Washington, D.C. The BID contains (1) a summary of all the public comments made on the proposed regulation; (2) a summary of the data EPA has obtained since proposal on SO_2, particulate matter, and NO_x emissions; and (3) the final Environmental Impact Statement which summarizes the impacts of the regulation.

Docket No. OAQPS-78-1 containing all supporting information used by EPA in developing the standards is available for public inspection and copying between 8 a.m. and 4 p.m., ge a11jn0.005Monday through Friday, at EPA's Central Docket Section, room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460.

The docket is an organized and complete file of all the information submitted to or otherwise considered by the Administrator in the development of this rulemaking. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the promulgated rule and EPA responses to significant comments, the contents of the docket will serve as the record in case of judicial review [section 107(d)(a)].

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: This preamble contains a detailed discussion of this rulemaking under the following headings: SUMMARY OF STANDARDS, RATIONALE, BACKGROUND, APPLICABILITY, COMMENTS ON PROPOSAL, REGULATORY ANALYSIS, PERFORMANCE TESTING, MISCELLANEOUS.

Summary of Standards

Applicability

The standards apply to electric utility steam generating units capable of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel, for which construction is commenced after September 18, 1978. Industrial cogeneration facilities that sell less than 25 MW of electricity, or less than one-third of their potential electrical output capacity, are not covered. For electric utility combined cycle gas turbines, applicability of the standards is determined on the basis of the fossil-fuel fired to the steam generator exclusive of the heat input and electrical power contribution of the gas turbine.

SO_2 Standards

The SO_2 standards are as follows:

(1) Solid and solid-derived fuels (except solid solvent refined coal): SO_2 emissions to the atmosphere are limited to 520 ng/J (1.20 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required at all times except when emissions to the atmosphere are less than 260 ng/J (0.60 lb/million Btu) heat input. When SO_2 emissions are less than 260 ng/J (0.60 lb/million Btu) heat input, a 70 percent reduction in potential emissions is required. Compliance with the emission limit and percent reduction requirements is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average. The percent reduction is computed on the basis of overall SO_2 removed by all types of SO_2 and sulfur removal technology, including flue gas desulfurization (FGD) systems and fuel pretreatment systems (such as coal cleaning, coal gasification, and coal liquefaction). Sulfur removed by a coal pulverizer or in bottom ash and fly ash may be included in the computation.

(2) Gaseous and liquid fuels not derived from solid fuels: SO_2 emissions into the atmosphere are limited to 340 ng/J (0.80 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required. The percent reduction requirement does not apply if SO_2 emissions into the atmosphere are less than 86 ng/J (0.20 lb/million Btu) heat input. Compliance with the SO_2 emission limitation and percent reduction is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average.

(3) Anthracite coal: Electric utility steam generating units firing anthracite coal alone are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit on a 30-day rolling average, and all other provisions of the regulations including the particulate matter and NO_x standards.

(4) Noncontinental areas: Electric utility steam generating units located in noncontinental areas (State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the applicable SO_2 emission limitation and all other provisions of the regulations including the particulate matter and NO_x standards.

(5) Resource recovery facilities: Resource recovery facilities that fire less than 25 percent fossil-fuel on a quarterly (90-day) heat input basis are not subject to the percentage reduction requirements but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit. Compliance with the emission limit is determined on a continuous basis using continuous monitoring to obtain a 30-day rolling average. In addition, such facilities must monitor and report their heat input by fuel type.

(6) Solid solvent refined coal: Electric utility steam generating units firing solid solvent refined coal (SRC I) are subject

the 520 ng/J (1.20 lb/million Btu) heat put emission limit (30-day rolling verage) and all requirements under the O$_x$ and particulate matter standards. ompliance with the emission limit is etermined on a continuous basis using continuous monitor to obtain a 30-day olling average. The percentage eduction requirement for SRC I, which s to be obtained at the refining facility tself, is 85 percent reduction in potential O$_2$ emissions on a 24-hour (daily) veraging basis. Compliance is to be etermined by Method 19. Initial full scale demonstration facilities may be granted a commercial demonstration permit establishing a requirement of 80 percent reduction in potential emissions on a 24-hour (daily) basis.

Particulate Matter Standards

The particulate matter standard limits emissions to 13 ng/J (0.03 lb/million Btu) heat input. The opacity standard limits the opacity of emission to 20 percent (6-minute average). The standards are based on the performance of a well-designed and operated baghouse or electostatic precipitator (ESP).

NO$_x$ Standards

The NO$_x$ standards are based on combustion modification and vary according to the fuel type. The standards are:

(1) 86 ng/J (0.20 lb/million Btu) heat input from the combustion of any gaseous fuel, except gaseous fuel derived from coal;

(2) 130 ng/J (0.30 lb/million Btu) heat input from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;

(3) 210 ng/J (0.50 lb/million Btu) heat input from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal;

(4) 340 ng/J (0.80 lb/million Btu) heat input from the combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, South Dakota, or Montana;

(5) Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from the NO$_x$ standards and monitoring requirements; and

(6) 260 ng/J (0.60 lb/million Btu) heat input from the combustion of any solid fuel not specified under (3), (4), or (5).

Continuous compliance with the NO$_x$ standards is required, based on a 30-day rolling average. Also, percent reductions in uncontrolled NO$_x$ emission levels are required. The percent reductions are not controlling, however, and compliance with the NO$_x$ emission limits will assure compliance with the percent reduction requirements.

Emerging Technologies

The standards include provisions which allow the Administrator to grant commercial demonstration permits to allow less stringent requirements for the initial full-scale demonstration plants of certain technologies. The standards include the following provisions:

(1) Facilities using SRC I would be subject to an emission limitation of 520 ng/J (1.20 lb/million Btu) heat input, based on a 30-day rolling average, and an emission reduction requirement of 85 percent, based on a 24-hour average. However, the percentage reduction allowed under a commercial demonstration permit for the initial full-scale demonstration plants, using SRC I would be 80 percent (based on a 24-hour average). The plant producing the SRC I would monitor to insure that the required percentage reduction (24-hour average) is achieved and the power plant using the SRC I would monitor to insure that the 520 ng/J heat input limit (30-day rolling average) is achieved.

(2) Facilities using fluidized bed combustion (FBC) or coal liquefaction would be subject to the emission limitation and percentage reduction requirement of the SO$_2$ standard and to the particulate matter and NO$_x$ standards. However, the reduction in potential SO$_2$ emissions allowed under a commercial demonstration permit for the initial full-scale demonstration plants using FBC would be 85 percent (based on a 30-day rolling average). The NO$_x$ emission limitation allowed under a commercial demonstration permit for the initial full-scale demonstration plants using coal liquefaction would be 300 ng/J (0.70 lb/million Btu) heat input, based on a 30-day rolling average.

(3) No more than 15,000 MW equivalent electrical capacity would be allotted for the purpose of commercial demonstration permits. The capacity will be allocated as follows:

Technology	Pollutant	Equivalent electrical capacity MW
Solid solvent-refined coal	SO$_2$	5,000–10,000
Fluidized bed combustion (atmospheric)	SO$_2$	400–3,000
Fluidized bed combustion (pressurized)	SO$_2$	200–1,200
Coal liquefaction	NO$_x$	750–10,000

Compliance Provisions

Continuous compliance with the SO$_2$ and NO$_x$ standards is required and is to be determined with continuous emission monitors. Reference methods or other approved procedures must be used to supplement the emission data when the continuous emission monitors malfunction, to provide emissions data for at least 18 hours of each day for at least 22 days out of any 30 successive days of boiler operation.

A malfunctioning FGD system may be bypassed under emergency conditions. Compliance with the particulate standard is determined through performance tests. Continuous monitors are required to measure and record the opacity of emissions. This data is to be used to identify excess emissions to insure that the particulate matter control system is being properly operated and maintained.

Rationale

SO$_2$ Standards

Under section 111(a) of the Act, a standard of performance for a fossil-fuel-fired stationary source must reflect the degree of emission limitation and percentage reduction achievable through the application of the best technological system of continuous emission reduction taking into consideration cost and any nonair quality health and environmental impacts and energy requirements. In addition, credit may be given for any cleaning of the fuel, or reduction in pollutant characteristics of the fuel, after mining and prior to combustion.

In the 1977 amendments to the Clean Air Act, Congress was severely critical of the current standard of performance for power plants, and especially of the fact that it could be met by the use of untreated low-sulfur coal. The House, in particular, felt that the current standard failed to meet six of the purposes of section 111. The six purposes are (H. Rept. at 184–186):

1. The standards must not give a competitive advantage to one State over another in attracting industry.

2. The standards must maximize the potential for long-term economic growth by reducing emissions as much as practicable. This would increase the amount of industrial growth possible within the limits set by the air quality standards.

3. The standards must to the extent practical force the installation of all the control technology that will ever be necessary on new plants at the time of construction when it is cheaper to install, thereby minimizing the need for retrofit in the future when air quality standards begin to set limits to growth.

4 and 5. The standards to the extent practical must force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it

Air Pollution and Acid Precipitation

Background

Emissions of air pollutants can result from the mining and cleaning of coal, its transportation and its combustion. Dust emitted from surface mining operations, from hopper cars in transit and from storage piles can be controlled by wetting the coal or by spraying on a bituminous coating and by collection of dust at the transfer points. The technology for such control is well established and the cost is moderate.

On the other hand, the combustion of coal has the greatest potential for serious environmental effects. There can be both short term effects (up to one year) on the air quality in the immediate vicinity of the source (within 5-10 kilometers) and long term, long range effects on a receiving area extending at least several hundred kilometers from the source.

Local effects consist of increases in ambient concentrations of particulate matter, sulphur dioxide and nitrogen dioxide. These pollutants are emitted as a result of incombustible mineral matter in the coal, the oxidation of sulphur in the coal, and the oxidation of nitrogen in the fuel and in the air used for combustion. Excessive emissions of particulate matter resulting in opaque chimney plumes can pose an aesthetic problem; particulate matter co-existing with sulphur dioxide in sufficient concentrations can result in an increase in respiratory ailments. Sulphur dioxide in itself can cause foliar damage to sensitive species of plants. Nitrogen dioxide is associated with respiratory ailments in humans and can, in conjunction with sulphur dioxide, cause damage to plants. Other pollutants of concern are polyaromatic hydrocarbon and heavy metals, both of which have potential health effects.

It is possible to control local ambient concentrations of these pollutants by discharging them from a smokestack sufficiently tall to allow adequate atmospheric dilution to acceptable concentrations. According to the Annual Summaries of the National Air Pollution Surveillance Network, concentrations of sulphur dioxide, except for isolated brief periods comprising less than 0.1% of the year, are presently within the National Ambient Air Quality Objectives. Nitrogen dioxide concentrations are even lower. Concentrations of particulate matter exceed the National Air Quality Objectives more frequently in the Atlantic Region, but the source is usually dust raised by vehicular traffic, or in the case of Sydney, Nova Scotia, emissions from the iron and steel mill.

Generally speaking, therefore, the combination of particulate controls on presently coal-burning plants, the use of oil which contains practically no ash and dispersion from tall stacks keeps ambient concentrations within acceptable limits, but it does not address the cumulative long range effects of some of these pollutants, which are of greater concern. Sulphur dioxide and nitrogen dioxide may be further oxidized slowly in the atmosphere to sulphates and nitrates. The rate of transformation, and the rate of deposition to the ground (in the absence of precipitation) is relatively slow with the result that these secondary pollutants may travel several hundreds or thousands of kilometers through the atmosphere. Indeed, sulphate particles are an important contributor to the familiar summertime haze that reduces visibility not only in central Canada, but in the Atlantic Region as well.

When precipitation occurs within the polluted air mass, these sulphates and nitrates can be deposited on soil and water bodies as only partially neutralized dilute solutions of sulphuric and nitric acid. These events are known as "long range transport of air pollution" and "acid precipitation", although one phenomenon can occur without the other.

Potential effects of the deposition of free hydrogen ions include the acidification of bodies of fresh water with resulting reproductive failure and alteration of the food supply of sensitive fish such as salmon and trout. It may also cause a reduction in the fertility of soil due to increased removal of nutrients such as calcium from the top layers of the soil. It is generally conceded that the oceans are well-buffered against the effects of acid precipitation, and that agricultural lands are already receiving enough lime to counteract acid precipitation. The concern is with fresh water and with forest land.

From data collected by the Canadian Network for Sampling Precipitation (CANSAP) since 1975, precipitation in the Atlantic Region is definitely acidic, with a monthly pH ranging from 4.0 to 5.0 and a long term weighted mean pH of about 4.5. This means that the concentration of hydrogen ion is, on the average, about 12 times greater than that of precipitation in equilibrium with atmospheric carbon dioxide (pH = 5.6).

The CANSAP data indicate that the deposition of sulphur by precipitation is about 1 $g/m^2/year$. This value is about the same as that measured in southern Scandinavia (OECD, 1977).

The reported deposition by precipitation of nitrogen is much less than that of sulphur, about 0.2 to 0.4 $gN/m^2/year$. However, this value may be too small due to the biological degradation of nitrate in the monthly samples; the actual deposition may be much larger.

The deposition of hydrogen ions by precipitation is this region is about 20 to 30 $meq/m^2/year$, compared with 20 to 50 $meq/m^2/year$ in Scandinavia (OECD), 1977).

Not enough long term data exists in this region to establish whether or not the acidity of precipitation is increasing. However, long term data in the adjacent northeastern states (Likens, 1976) and precipitation gathered in Kentville, Nova Scotia, in the mid 1950's (Herman and Gorham, 1957) suggest that it probably has increased here during the past 25 years.

Because sulphur oxides (and to a lesser degree nitrogen oxides) are the major precursors of strong acid precipitation, the severity and extent of acid precipitation is often gauged by the sulphate and nitrate concentrations in precipitation, and the determination of the relative importance of local and distant sources in the deposition of acid is determined by carrying out sulphur and nitrogen budgets which often incorporate modelling, such as that done by Wiltshire (1979) and Lord (Paper enclosed).

Wet deposition is by far the most important process in this region for depositing sulphur from the atmosphere. Deposition by "dry" processes such as diffusion of sulphur dioxide gas and sulphate particles are less important, accounting for only 7% to 30% of the total deposition of sulphur (Wiltshire, 1979; Shaw, 1980). For this reason, the frequency and amount of precipitation and the wind direction when it occurs are important factors in the deposition of atmospheric acid.

Although the effects of acid precipitation on fish populations has been fairly well established in Scandinavia and in the vicinity of the large smelter complex in Sudbury, Ontario, no direct evidence exists that acid precipitation has adversely affected fish in this Region. It is known that the precipitation is acidic, and has probably become increasingly so during the past quarter century. It is also known that the concentration of hydrogen ion in certain rivers is southwestern Nova Scotia increased two to ten-fold during a 10 to 20 year period (Altshuller and McBean, 1979).

A survey of lakes in Nova Scotia and New Brunswick indicate that acidity has increased two to five times during the past 20 years (Wiltshire and Machell, 1980).

Therefore, while there is no direct evidence as yet linking acid precipitation with acidification of fresh water here in the Atlantic Region, the circumstantial evidence is very strong indeed when one considers the concurrent increases (since the mid 1950's) of emissions of sulphur and nitrogen oxides, and of acid levels in precipitation of fresh waters.

There is little doubt that the fresh water in this region has relatively little buffering capacity to neutralize the effects of acid precipitation, as shown by sensitivity maps based upon existing alkalinity, conductance and the concentration of the bicarbonate ion and calcium (Altshuller and McBean, 1979). Further increases in the deposition of atmospheric acid may eventually use up what little buffering capacity exists in these lakes, to be followed by even greater increased in their acidity. The study of Wiltshire and Machell (1980) has also revealed that the lakes in Nova Scotia and southern New Brunswick have relatively little buffering capacity left, and may undergo rapid increases in acidity in the next 10 to 30 years at the present rate of acidification. A more detailed assessment of the effects of increased deposition of atmospheric acid may be found in Wiltshire and Machell (Paper attached).

It is known that young salmon at a hatchery on one river in Nova Scotia (the Mersey) had a high mortality rate until the feed water to the hatchery was rendered less acidic by running it through a bed of limestone (G. Farmer, personal communication, 1979). It is very likely that acid precipitation may have been an important contributing factor to the mortality of the salmon.

Adverse effects of acid precipitation on the productivity of forest soils has not been established anywhere in the world. not even in Scandinavia where a lively debate rages as to the relative importance of acid precipitation and other environmental stresses such as forestry practices. It is felt that in Scandinavia any adverse effects from acid precipitation may take 75 to 100 years to distinguish themselves from other stresses such as improper forestry practices (Odén, 1980).

Nevertheless, the soils in this region are mostly acidic podzols from which nutrients are easily reached by acid precipitation (Altshuller and McBean, 1979). Because of the very high value of the forestry industry in this region, even a 10% to 20% loss in forestry productivity would be a significant economic loss.

In this report, Wiltshire and Machell (paper attached) will examine only the effects upon fresh water.

In summary, the present rate of deposition of atmospheric acid, and the potential effects upon fresh water and forest soils is a matter of great concern. Any increase in this deposition brought about by an increase in the conbustion of coal without proper emission controls in this region will only accelerate the effects that are believed to be occuring at the present time. The increase in effects due to the increase in coal combustion without controls will be estimated, and the possible alternate actions examined carefully.

Factors

Because the deposition of atmospheric acid in this region is a result of emissions from sources both within and outside the region (Wiltshire, 1979; Lord, 1980; Shaw, 1980) and from sources other than coal-burning boilers, environmental factors to be considered in the examination of alternative approaches are:

i) The contribution of regional power plants to the present rate of deposition of atmospheric acid;

ii) The potential increase of deposition due to the conversion of presently oil-fired regional power plants to coal and the construction of new coal-burning units.

Wiltshire (1970) in his sulphur budget for Nova Scotia, estimated that, in 1976, deposition from Nova Scotia sources accounted for 25% of the total atmospheric deposition of sulphur in the province; import from outside the province accounted for 75%. Shaw (1980) in a meteorological analysis of the deposition of hydrogen ion and sulphur at a sampling station 25 km west of Halifax estimated that 60% of the deposition comes from the direction of Halifax, to a large extent during storms with easterly winds. These results indicate that, although the prevailing winds are westerly and are popularly though to carry away emissions from regional sources, in fact significant deposition of atmospheric acid from local sources occurs often during precipitation accompanied by easterly winds which carry the emissions inland rather than out to sea.

Lord (1980) has extended Wiltshire's sulphur budget to the remaining three provinces in the region. His estimates of the present contribution of regional sources to the deposition of sulphur within each province is shown in his paper. Hamilton (Paper 5) and Lord (Paper 4) estimate increases in emissions and depositions, respectively, of acid forming compounds due to several scenarios of conversion of power plants to coal, Wiltshire and Machell (Paper 3) then use these estimates of increases in deposition to predict decreases in the pH of fresh water bodies in this region.

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POTENTIAL AQUATIC EFFECTS OF INCREASED ACID DEPOSITION DUE TO EXPANDED USE OF COAL FOR POWER GENERATION IN THE ATLANTIC REGION

by J. WILTSHIRE & J. MACHELL

Potential Aquatic Effects of Increased Acid Deposition Due to an Expanded Use of Coal for Power Generation in the Atlantic Region

Purpose

The existing literature on the effects of acid rain shows clearly that dilute aquatic ecosystems are the first part of the environment to exhibit readily observable adverse biological effects. The purposes of this Appendix are to: a) provide information on the sensitivity to acidification of fresh water systems in the Atlantic Region; b) review the current evidence for acidification of rivers and lakes in the region during the past 20 to 30 years; and c) to assess the possible increases in sulphur deposition identified in the preceding Appendix* with respect to their potential impact on aquatic communities.

Sensitivity of Surface Waters in the Atlantic Region to Acidification

Recent surveys of the available date for rivers and lakes in the Atlantic Provinces have pointed to the high susceptibility to acidification of freshwater systems over most of the region (Altshuller and McBean, 1979; Clair et al, 1979). The relative sensitivities of surface waters in the region are indicated in a general way in Figures 1 and 2. The regions described as highly sensitive and sensitive in these Figures are those characterized by lakes and rivers with mean pH values less than or equal to 6.5 and 7.0 respectively. The Figures are based principally on the pH distribution maps from Clair et al (1979) and the general picture is in good agreement with the sensitivity maps in the earlier study (Altshuller and McBean) which were based on a number of other chemical criteria. In general, the potential for acidification of freshwater systems due to continued acid loading at current or increased rates exists over most of New Brunswick, Nova Scotia and insular Newfoundland. Of particular concern are the broad regions in mainland Nova Scotia, Newfoundland and portions of southern and central New Brunswick, where pH, alkalinity and CSI* values of lakes and rivers indicate minimal buffering capacity.

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*Changes in SO_2 Emissions and Sulphur Depositions in the Atlantic Region from an Expanded Use of Coal for Power Generation (D. A. Lord).

* The CSI (calcite saturation index) of a water is a measure of its under-saturation with respect to calcium carbonate.

Geologically, these regions are characterized by igneous and metamorphic bedrock types which are highly resistant to weathering processes and lead to relatively non-calcareous soils. Alkalinities of lakes in these regions of Nova Scotia and New Brunswick have been found to be typically less than 50 μeq/l, which is considerably less than the level of 200 to 300 μeq/l selected as a criterion for high sensitivity in Altshuller and McBean (1979). The pH frequency distributions of rivers and lakes in Nova Scotia and New Brunswick are indicated in Figure 3. The distributions shown are based on data from a number of sources (Principally river water quality data from the National Water Quality Data Bank and preliminary data from an ongoing EPS study of lakes in Nova Scotia and New Brunswick) and have been smoothed by a graphical method. These histograms should be regarded as preliminary, but are considered to be representative of surface waters in the two provinces. On the basis of the pH criteria employed in the sensitivity map in Figure 1, essentially all of the lakes and rivers in the histogram for Nova Scotia are indicated to be sensitive to acidification (pH <7). The cumulative percentages for highly sensitive freshwater systems (pH <6.5) are approximately 70% for Nova Scotia and 35% for New Brunswick. These percentages are in generally good agreement with the areal sensitivities indicated in Figure 1, and clearly demonstrated the much lower pH values which characterize surface waters in Nova Scotia.

Of particular interest is the bimodal pH distribution for Nova Scotia, a feature which is frequently observed for softwater lakes in regions receiving acidic precipitation (Wright and Gjessing, 1976). Such a pH distribution with a minimum in the region of pH 5.5 is theoretically predictable for bicarbonate buffering in an area where the net input of acids and bases is closely balanced. Due to differences between individual water sheds, the input of bases will in some cases exceed that of acids (alkalinity > 0), and in other cases the reverse will hold (alkalinity < 0). The effect on pH of small differences in alkalinity is greatest in the region [Alk]~0, with the result that a) the pH probability curve passes through a minimum at pH ~ 5 (Figure 3(a)); b) the decrease in pH for a given addition of acid increases as the pH approaches 5.5; and c) the short-term fluctuations in pH increase in magnitude as the pH approaches 5.5.

Current Evidence for Acidification of Surface Waters in the Atlantic Region

The historical precipitation data suggests that acidic precipitation became a synoptic phenomenon in the Atlantic Region no earlier than the late 1950's (Shaw, 1979). There is now considerable evidence for a widespread decrease in the pH of surface waters in Nova Scotia during the ensuing 20 to 30 years. Analysis of the water quality data for 16 major rivers (Altshuller and Bean, 1979; Elder, 1979) has shown declines in pH of 0.2 to 1.2 pH units since 1955. (Table 1). The decrease in pH is particularly pronounced for rivers in southwestern Nova Scotia where geological factors lead to high sensitivity to acidification.

Watt (1979) resampled a number of lakes in the Halifax area, for which reliable historical data exist (Gorham, 1957), and found pH decreases varying between 0.1 and 0.8 pH units. (Table 1). These pH changes were considered to be largely attributable to the effects of local emissions, and there is a clear need for further study in this area.

In Table 2 are presented the current and historical pH data for a number of lakes distributed throughout mainland Nova Scotia and southern New Brunswick (Wiltshire and Machell, 1980). The pH decreases are seen to be confined to the post-1950's period, which is consistent with the apparent history of the acidity of precipitation in the region.

There is currently no clear indication that comparable declines in the pH of surface waters has occured in other parts of the Atlantic Region (Tom Clair, I.W.D., pers. comm.). Preliminary analysis of the historical data indicates that if pH levels have decreased, the changes have been relatively small and careful statistical treatments of the data are required before any conclusions can be drawn. Work in this area is currently in progress, with particular emphasis being placed on the data for regions in New Brunswick and Newfoundland, which have been identified as highly sensitive (Figures 1 and 2).

Estimation of Surface Water pH Changes Due to Increased Deposition of Acidic Sulphur Compounds

Estimates of the annual rate of sulphur deposition (current and projected) in the four Atlantic provinces are given in the preceding Appendix. For the three coal use alternatives described (A, B and C) the changes in sulphur deposition from 1980 are small (-.05 to +.01 tonnes S/km^2yr) if emission controls are applied. However, in the absence of emission controls, quite substantial increases in deposition have been predicted for all three alternatives, particularly in Nova Scotia, New Brunswick and Prince Edward Island (Table 3).

The quantitative estimate given here of the potential impact of these increased sulphur depositions on surface waters in the region must be regarded as highly speculative at this time. Our understanding of the various geochemical and biological processes which alter the chemical composition of precipitation both before and after its entry into a freshwater body is still highly imperfect. The manner in which the observed acidification of surface waters in regions of North America and Europe is related to atmospheric depositions, other cultural effects, and natural acidifying processes is currently an area of active discussion and research.

A prediction of this nature will necessarily involve the following three steps:

1. Conversion of the projected increases in sulphur deposition (Table 3) to projected increases in atmospheric loading of acid to the aquatic regime.

2. Estimation of the changes which will occur, as a consequence of increased atmospheric acid imput, in the current net balance between acids and bases provided to surface waters by other environmental components (interactions with forest canopies, ion exchange and biological processes in soils, bedrock weathering processes, interactions with river and lake sediments, etc.)

3. From the net change in the alkalinity of surface waters resulting from the above two estimates, calculation of the corresponding pH changes on the basis of the pH-alkalinity relationship of surface waters in the region.

In performing the conversion of increases in sulphur deposition (in tonnes S/km^2yr) to increases in hydrogen ion loading (μeq/l), one mole of sulphur has been treated as being equivalent to two moles of acid (i.e., $S \rightarrow H_2SO_4$), and the volume of surface water containing this acid has been calculated assuming a mean annual precipitation of 1300 mm/yr and an annual evapotranspiration effect of 30%. The latter values are estimated means based on data for Nova Scotia (Hydrological Atlas of Canada, 1978). The resulting increases in strong acid of atmospheric origin for the three coal use alternatives without emission controls are given in Table 3. Only increases in deposition from the estimated 1980 rate have been considered. Not included in the calculations are the potential acid forming effect of increased emissions of oxides of nitrogen, or the possibility that a portion of the increased sulphur emissions may be non-acidic (i.e. neutralized by increased emissions of bases). The value shown in the table can be compared with the current atmospheric acid loading level which is estimated to be approximately 50 μeq/l (this value is obtained from the current mean pH of 4.5 for precipitation at CANSAP stations in Nova Scotia, adjusted for dry deposition (R. Shaw, pers. comm.) and for a 30% mean evapotranspiration effect).

With respect to the second step in this calculation, it has been assumed that the relatively small increase in acid level due to atmospheric loading (from 50 μeq/l to 68 μeq/l at most) will result in no significant changes in the amount of neutralization being provided by the various watersheds in the region. In effect, an increase in acid loading of X μeq/l has been assumed to result in a decrease in the alkalinities of surface waters of X μeq/l. To the extent that the watersheds may have a reserve neutralizing capacity, and will hence respond by an increased input of bases, the calculated decreases in surface water pH will be in error. In this sense the calculated effects should be regarded as the maximum effects which may occur as a result of the increased sulphur depositions being considered.

Completion of the calculations involves correction of the alkalinities of surface waters in the region by the amounts calculated above, and then calculation of new pH values from the appropriate pH-alkalinity relationship. Difficulties arise here in that to our knowledge, little of a quantitative nature is currently known about the species which buffer the surface waters in the region, and the methodology which has been employed in routine alkalinity determinations does not yield alkalinity values of adequate precision for these calculations (particularly at the low levels which characterize many of the rivers and lakes). The alkalinities of soft-waters are generally considered to be principally due to the bicarbonate ion (equation 1), although in colored waters of low alkalinities, a contribution by weak organic bases may become significant.

$$[Alk] = [HCO_3^-] - [H^+] = \frac{K_1 [H_2CO_3]}{[H]} - [H] \quad (1)$$

In a study of 16 lakes in Nova Scotia and New Brunswick (pH range 4.4 to 7.0), the relationship between pH and alkalinity (determined by the Gran method) was found to be consistent with equation 1 either with CO_2 levels at 2 to 4 times the calculated value for equibrium with the atmosphere or with an additional contribution by organic bases (Wiltshire and Machell, 1980). In calculating the effect on pH of a decrease in alkalinity (Figure 4), the surface waters of Nova Scotia and New Brunswick has been assumed to follow the quantitative pH-alkalinity relationship found by Wiltshire and Machell.

As shown in Table 2, the three coal use alternatives result in estimated increases in acid loading to surface waters in Nova Scotia between 5 and 8 μeq/l. For New Brunswick surface waters, a similar value (7 μeq/l) is obtained under alternative A, but significantly higher values (16 and 18 μeq/l) are obtained under alternatives B and C. The pH changes resulting from a decrease in alkalinity of 7 μeq/l have thus been employed to represent the potential effects in Nova Scotia under all three alternatives and in New Brunswick under alternative A, while the effect of a decrease in alkalinity of 17 μeq/l has been employed for New Brunswick surface waters under alternative B and C. That these seemingly minor potential changes in alkalinity would have a considerable impact on freshwaters of low buffering capacity is demonstrated by the curves in Figure 4. From curve a, which represents a decrease in alkalinity of 17 μeq/l) a maximum pH change of 0.8 units is calculated (from pH 5.8 to 5.0), and from curve b ($\Delta[Alk] = -7$ μeq/l) a maximum pH change of 0.4 units is obtained (from pH 5.6 to 5.2). On the other hand, as one considers lakes with progressively higher current pH values, the ability to withstand increased acid loading is seen to increase dramatically. For example, a well buffered lake at pH 7.5 is calculated to undergo a pH decrease of only.02 units as a result of a decrease in alkalinity of 17 μeq/l. These figures demonstrate quite clearly how readily an aquatic system may pass through the pH range 6 to 5, the reason for considering a lake or river with pH 6.5 to be a very fragile ecosystem, and the significance (with respect to sensitivity to acidification) of the pH distributions in Figure 3.

Potential Impact on Aquatic Communities

The potential effects of the three coal use alternatives (without SO_2 controls) on the pH frequency distribution of surface waters in Nova Scotia and New Brunswick are shown in Figure 5. The current cumulative distributions are based on the smoothed histograms in Figure 3, and the projected distributions are based on the calculated pH changes in Figure 4. For Nova Scotia, all three coal use alternatives have been assumed to result in a decrease in alkalinity of the order of 7 μeq/l (curve b in figure 4). For New Brunswick, the same alkalinity change (and corresponding pH changes) has been assumed for coal use alternative A, while the effects of alternatives B and C are based on a decrease in alkalinity of 17 μeq/l (curve a in Figure 4). The changes in the percent of surface waters at a few selected pH values (4.5, 5.0 and 6.0) have been interpolated from Figure 5 and included in Table 3.

Should they occur, the projected pH changes shown in Figure 5 and Table 3 would be expected to cause significant changes in the ecology of many lakes and rivers in the two provinces. For example, a decline in pH to values below 6 may result in decreases in the diversity of phytoplankton, zooplankton, benthic invertebrates and fish populations by the gradual elimination of sensitive species (Grahn, 1974; Wright and Gjessing, 1975; Beamish, 1976; Leivestad et al, 1978). Once pH levels reach 5.5 - 5.0, it has been reported that Atlantic Salmon reproduction will be reduced (Jensen and Snekvik, 1972) and sublethal effects such as histological damage to gill surfaces can occur in Brook Trout (Daye and Garside, 1976).

The shift of waters below pH 5 is reported to result in the eventual elimination of most fish species. Decreased reproductive success is accompanied by increased physiological stress due to lowered blood pH, body sodium levels (Packer and Dunson, 1970, Neville, 1979) and decreased tolerance to lowered oxygen levels (Wiebe et al 1934). Elevated levels of certain metals such as aluminum in Lake water may also result from such a decrease (Dickson, 1979). Cronan and Schofield (1979) in laboratory studies with Brook Trout report toxic effects of aluminum concentrations above 200 ppb and reduced growth at concentrations of 100 to 300 ppb. Recent studies of Maritime lakes in the pH range 4.4 to 5.0 have recorded mean aluminum levels of 100 to 210 ppb and maximum values of 380 ppb (Wiltshire and Machell, 1980).

Daye and Garside (1979) conclude that Atlantic Salmon will decline and eventually disappear from freshwater areas when pH approaches 4.5 for an extended period. Below pH 4.5, species such as Brown Bullhead, White Sucker, Brook Trout, Yellow Perch and Lake Chub are known to be eliminated (Beamish, 1976, Schofield, 1976).

Conclusions

The watersheds over much of the Atlantic Region provide little or no buffering capacity to surface waters, with the result that these surface waters are highly susceptible to the effects of increased acid loading. There is evidence that many lakes and rivers, particularly in Nova Scotia, have undergone substantial pH declines during the past 20 to 30 years, and many of these freshwaters are currently at pH levels where the survival of sensitive species is either not possible or is endangered.

Calculations based on the current pH frequency distributions of surface waters in Nova Scotia and New Brunswick indicate that with only minor decreases in alkalinity the pH of many more lakes and rivers will reach levels where reductions in the populations and diversity of aquatic biota at various trophic levels will occur.

Estimates have been made of the increased atmospheric acid loading to the pedosphere and lithosphere which may result if sulphur emission controls are not incorporated in the expanded use of coal for power generation in the Region. If these increases in acid deposition result in comparable declines in the alkalinities of surface waters, a significant deterioration in an already serious environmental problem is to be expected.

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Table 1. Reported declines in the pH of rivers and lakes in Nova Scotia.

Rivers[a]	pH		ΔpH	Lakes(Halifax area)[b]	pH		ΔpH
	1954-55	1969-77			1955	1977	
Roseway	5.1	4.4	-.7	Purcell's Pond	3.95	3.89	-.06
Sissiboo	5.6	4.7	-.9	Silver Lake	4.46	4.20	-.26
Tusket	5.7	4.7	-1.0	Black Lake	4.50	4.31	-.19
Mersey	5.8	4.9	-.9	Duncan Lake	4.58	4.25	-.33
Medway(downstream)	6.0	5.3	-.7	Long Lake	4.82	4.37	-.45
Medway(upstream)	6.2	5.0	-1.2	Hubley's Big Lake	4.84	4.56	-.28
LaHave	6.2	5.9	-.3	Purcell's Cove Slate Quarry	4.89	4.79	-.10
St. Mary's	6.3	6.1	-.2	Lewis Lake	4.96	4.62	-.34
Musquodoboit	6.7	6.4	-.3	Railway Pond	5.22	4.67	-.55
Mira(tidal)	6.8	5.9	-.9	Webber Lake	5.38	4.60	-.78
Annapolis	7.0	6.8	-.2	Baptizing Lake	5.76	5.06	-.70
				Mt. Uniacke Gold Mines Lake	5.94	5.40	-.54
				Brine Lake	6.38	6.05	-.33
				Fraser Lake	6.44	5.80	-.64
				Crossgill Lake	6.60	5.80	-.80
				Nelsen Lake	6.70	6.17	-.53

a) data from Altshuller and McBean(1979).
b) 1955 data from Gorham (1957); 1977 data from Watt et al (1979).

Table 2. Observed pH changes in Nova Scotia and New Brunswick lakes during the period 1940 to 1979.

Lake	pH			ΔpH	
	ça 1940[a]	1950's[b]	1979[c]	pre-1950's	post-1950's
Boarsback (N.S.)	4.7	4.7	4.4	.0	-.3
Jesse (N.S.)	6.5	6.5	5.8	.0	-.7
Lily (N.S.)		6.5	5.8		-.7
Kerr (N.B.)	6.8	6.6	6.0	-.2	-.6
Crecy (N.B.)	6.7	6.7	6.0	.0	-.7
Tedford (N.S.)	6.3	6.6	6.3	+.3	-.3
Sutherland (N.B.)		7.0	6.3		-.7
Gibson (N.B.)	7.0	6.7	6.4	-.3	-.3
Blackbrook (N.S.)		6.8	6.4		-.4
Copper (N.S.)		7.3	7.0		-.3
Means				.0	-.5

a) data from Smith (1937 a,b, 1948, 1952, 1961)

b) data from Hayes and Anthony (1958)

c) data from Wiltshire and Machell (1980)

Table 3. Estimated effects of increased coal combustion without SO_2 emission controls for power generation in the Atlantic Region. Projected increases in atmospheric acid loading to surface waters and potential effects on the pH distribution of surface waters.

province	coal use alternative	estimated increase in deposition (from 1980)		alkalinity change assumed (µeq/l)	Percent of surface waters (cumulative)*					
		tonnes S/km^{2}yr	µeqH+/l		pH ≤ 4.5		pH ≤ 5		pH ≤ 6	
					cur.	pro.	cur.	pro.	cur.	pro.
Nova Scotia	A	+.08	+5	-7	9	13	27	34	46	51
	B	+.13	+8							
	C	+.11	+7							
New Brunswick	A	+.12	+7	-7	0	0	0	0	10	16
	B	+.25	+16	-17	0	0	0	6	10	24
	C	+.29	+18							
Prince Edward Island	A	+.11	+7	no calculation performed						
	B	+.17	+11							
	C	+.23	+14							
Newfoundland	A	+.02	+1	no calculation performed						
	B	+.05	+3							
	C	+.08	+5							

(*cur.=current,pro.=projected)

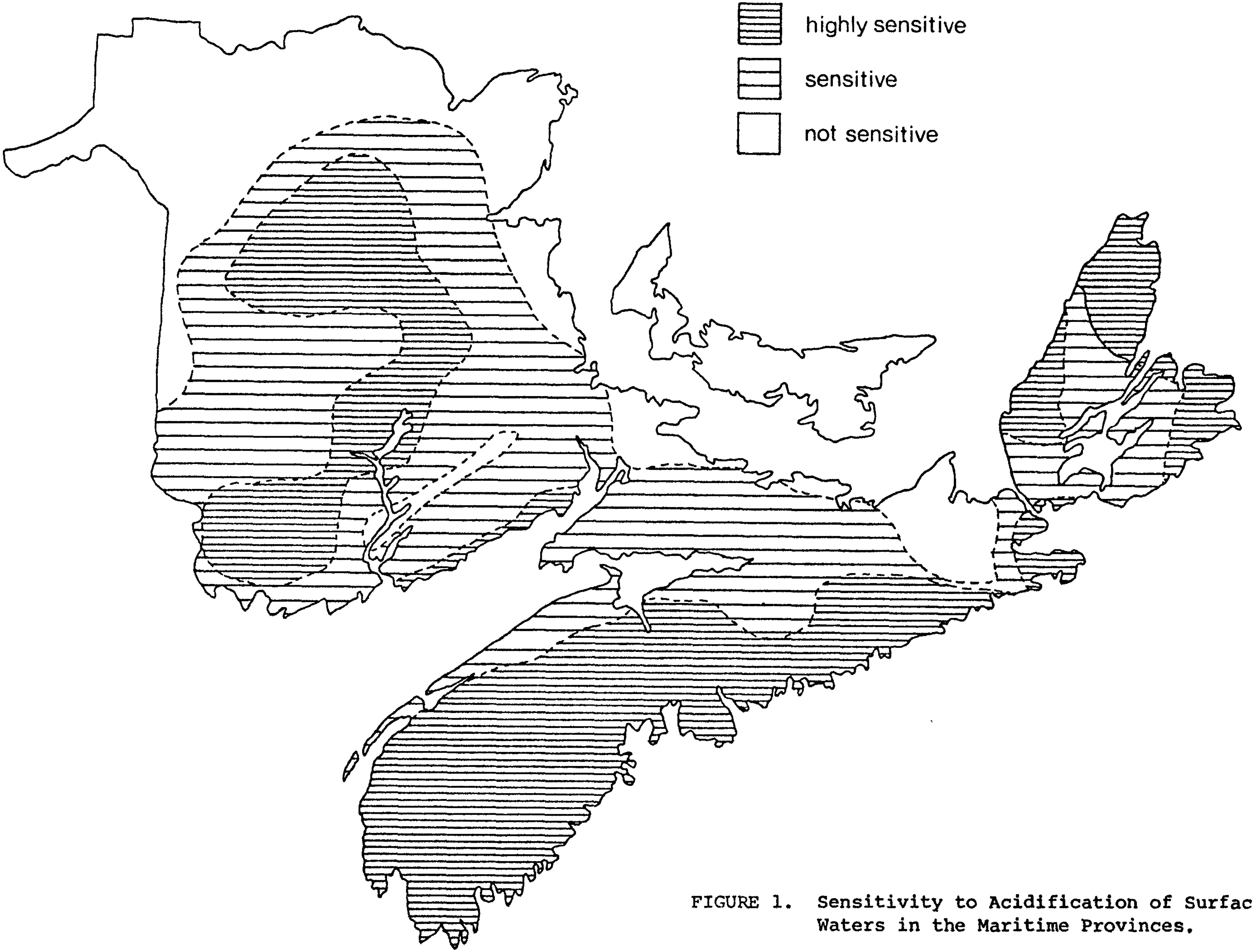

FIGURE 1. Sensitivity to Acidification of Surface Waters in the Maritime Provinces.

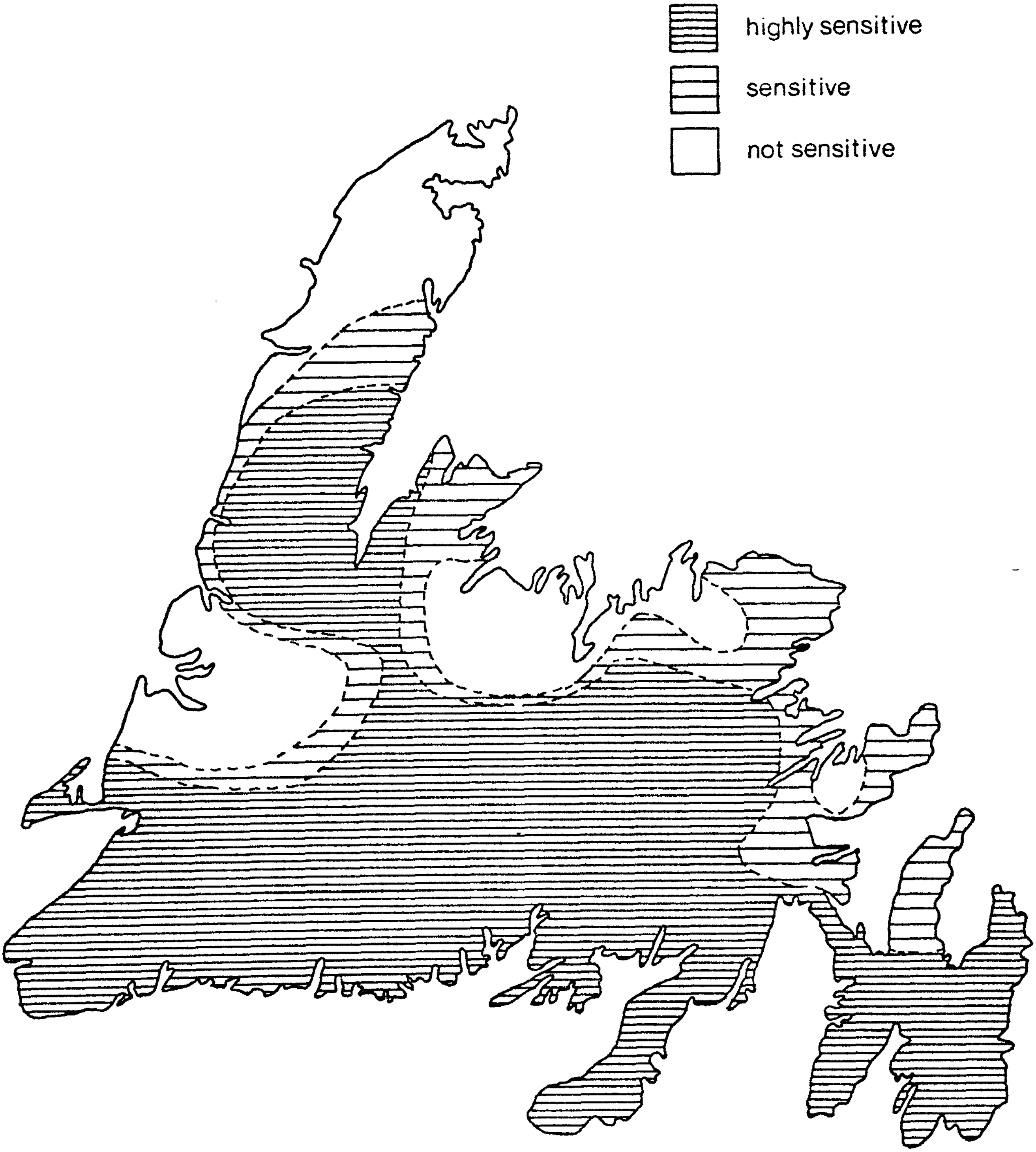

FIGURE 2. Sensitivity to Acidification of Surface Waters in Insular Newfoundland

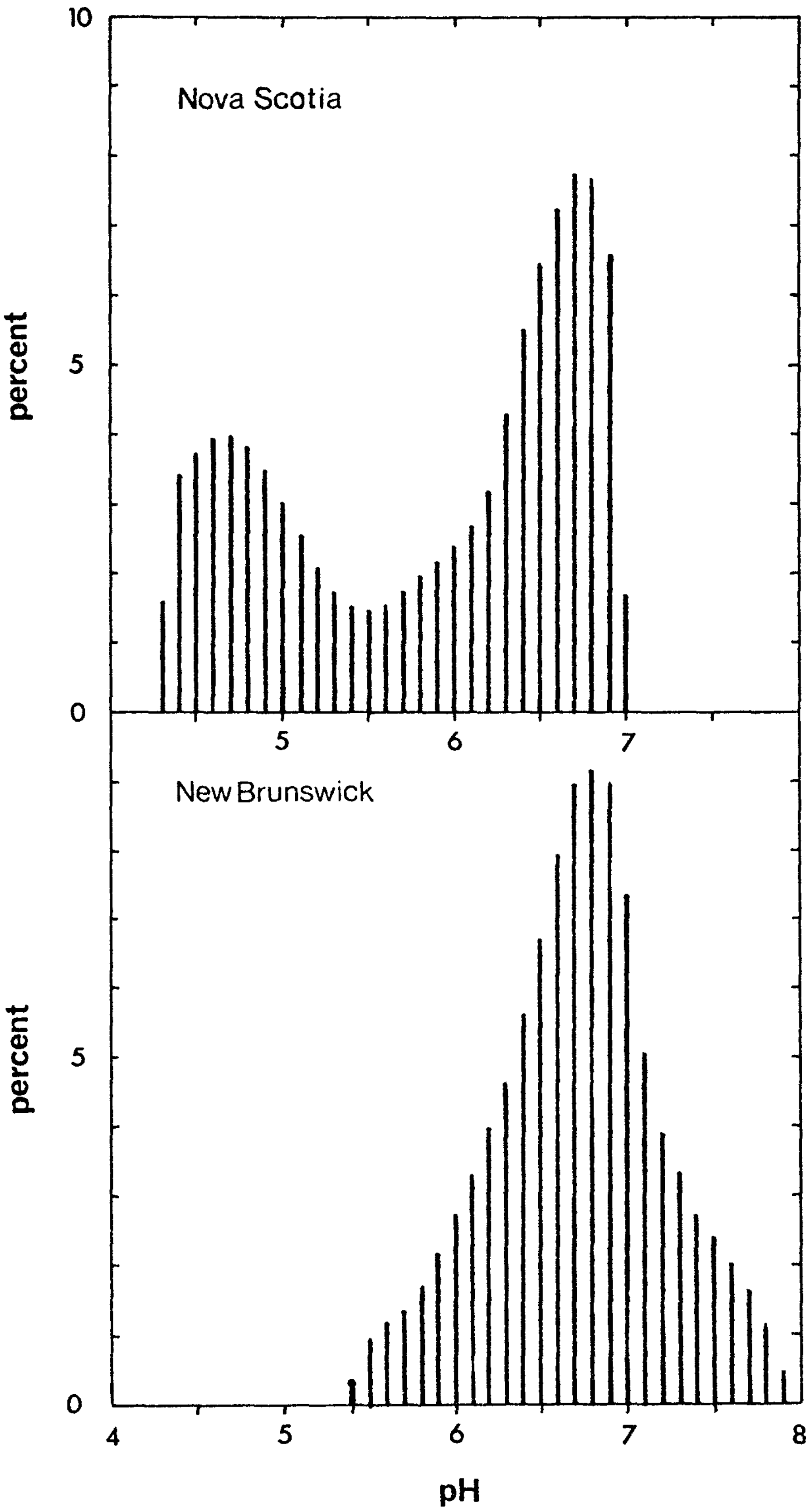

FIGURE 3. Frequency Distributions of Surface Water pH Values in Nova Scotia and New Brunswick.

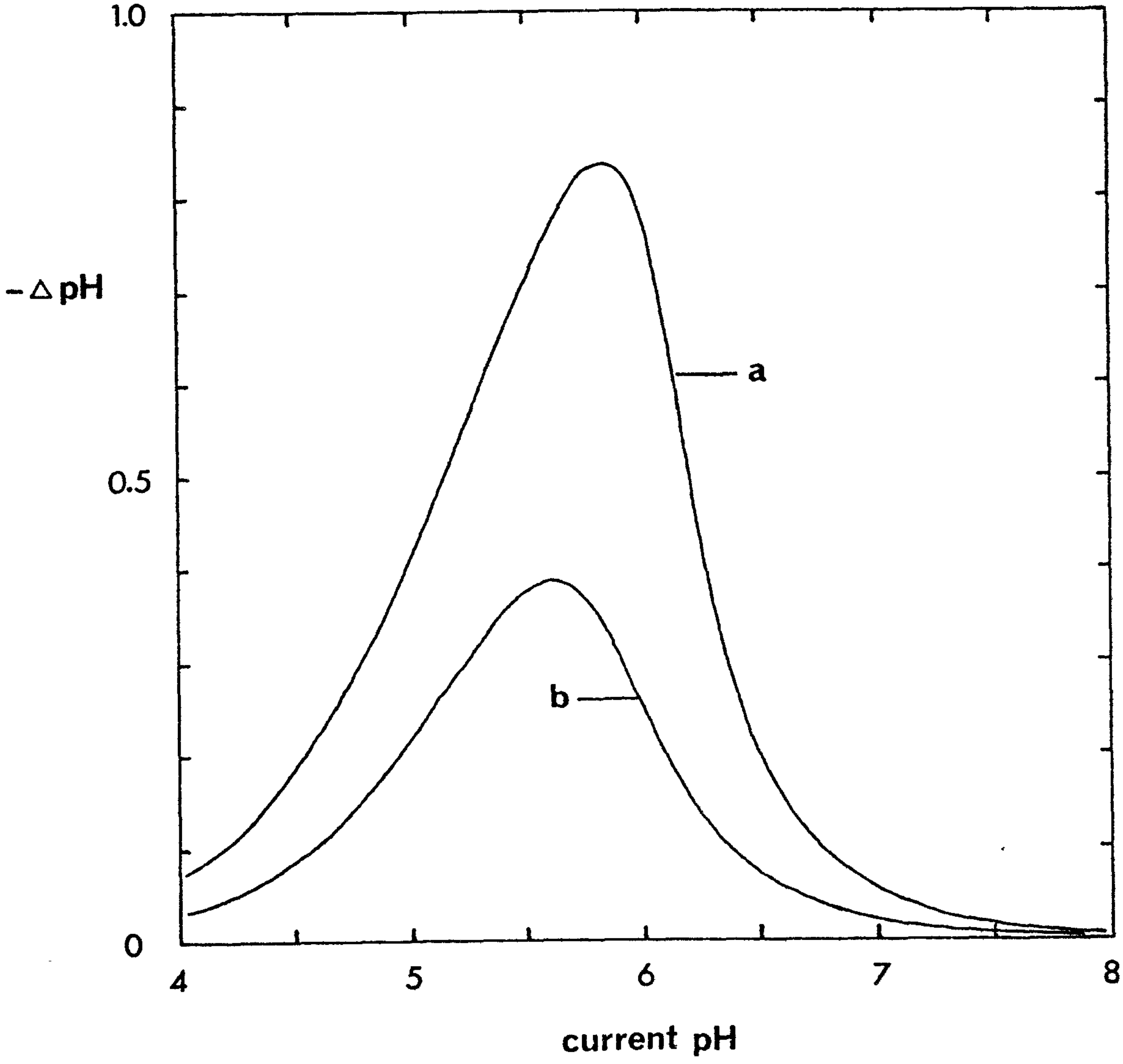

FIGURE 4. Susceptibility of Freshwater Systems to Acidification. The Calculated pH Changes are Based on the Relationship $[Alk] = (10^{-10.84}/[H]) - [H]$ with $\Delta[Alk] = -17 \mu eq/l$ (curve a) and $-7 \mu eq/l$ (curve b)

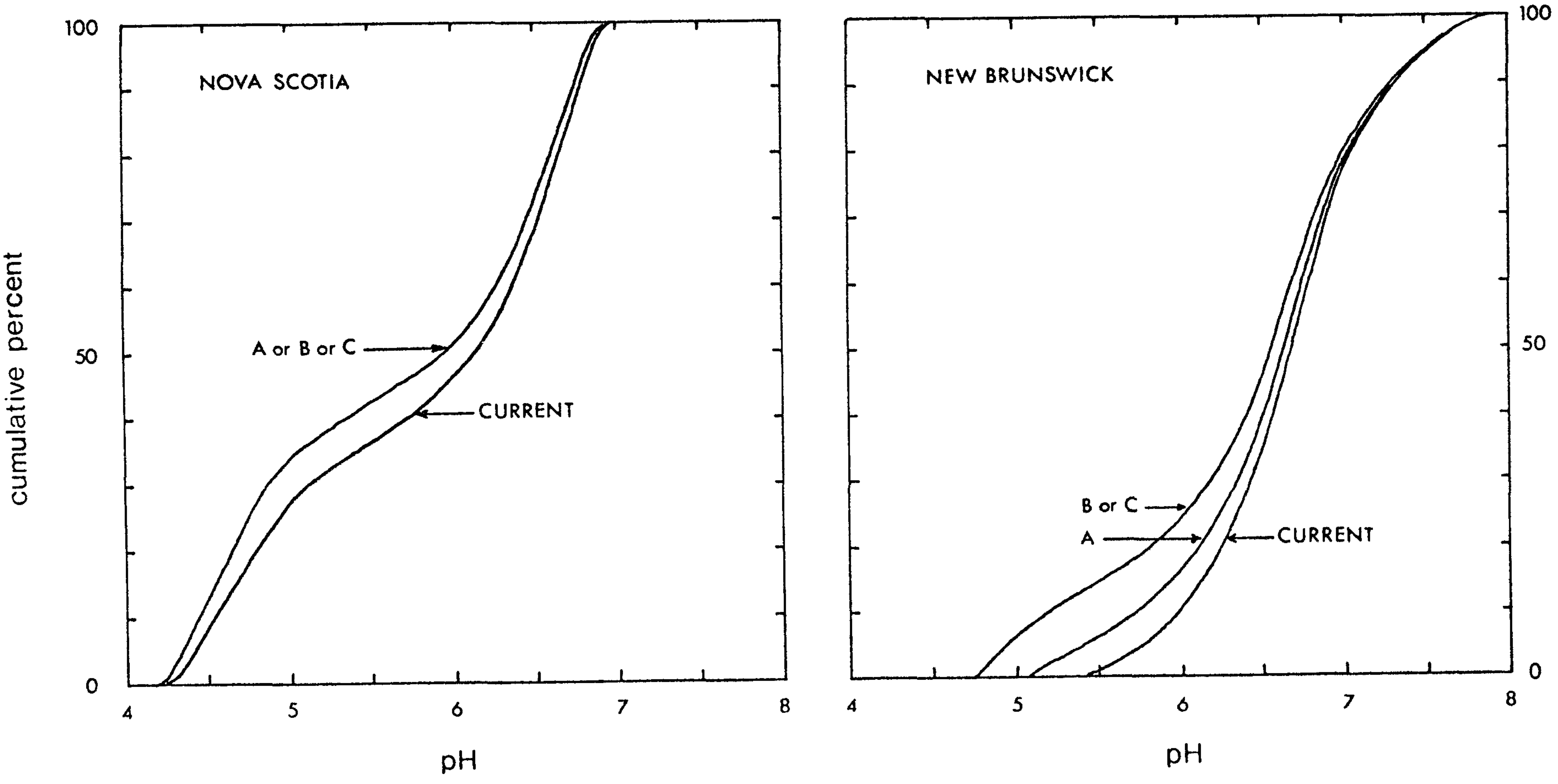

FIGURE 5. Current and Projected pH Frequency Distributions (cumulative) of Surface Waters in Nova Scotia and New Brunswick. The Current Distributions are Approximate only and the Projected Distributions are Based on the Alkalinity Changes in Table 3.

CHANGES IN SO_2 EMISSIONS AND SULPHUR DEPOSITIONS IN THE ATLANTIC REGION FROM AN EXPANDED USE IN COAL FOR POWER GENERATION

by D. A. LORD

Changes in SO_2 Emissions and Sulphur Depositions in the Atlantic Region from an Expanded Use of Coal for Power Generation.

1. Introduction

Further expansion in the use of coal for power generation in the Atlantic Provinces will result in an increase of emissions to the atmosphere from power generating facilities unless adequate emission controls are implemented. Emissions will include oxides of sulphur (SO_x), oxides of nitrogen (NO_x), as well as particulates containing heavy metals. An increase in emissions of complex organics such as PAH's (polycyclic aromatic hydrocarbons) is also anticipated.

Currently, the major concern with atmospheric emissions centres on the resultant environmental damage which can occur through acidification when the oxides of sulphur and nitrogen combine with water to form weak mineral acid solutions which are then deposited.[1] The transportation and deposition patterns of sulphur compounds are better understood. Consequently, the prediction of sulphur loadings to receiving environments by the use of appropriate numerical models is the principal method currently used for providing information to assess the extent of environmental changes that will result from increased atmospheric emissions with fossil fuel combustion.

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[1] It is generally acknowledged that sulphur compounds contribute 2/3 of the total acidity loading to a given receiving environment, while nitrogen compounds contribute 1/3.

A model describing the long range transport and deposition patterns of sulphur compounds from emissions within the Atlantic Provinces has been developed. Depositions are described by an appropriate decay curve (Figure 1), in which the fraction of emitted sulphur still remaining in the atmosphere with increasing distance, is detailed. Major variations in meteorological conditions controlling depositions are accounted for by estimating both minimum as well as maximum rates of deposition. Annualized deposition rates are computed from the mean of the maximum and minimum deposition rates. These maximum and minimum rates represent the range of actual deposition rates which occur under the normal variations of meteorological conditions in the Maritimes during any one year. Maximum rates would be expected to occur with easterly winds and concurrent precipitation (where, at specific sites close to sources, deposition rates may exceed those indicated in Figure 1); while minimum rates would be expected to occur with southwesterly winds and good atmospheric mixing.

All of the above comments refer specifically to the deposition of sulphur compounds of local origin. Ironically, it is under conditions of southwesterly winds that the maximum total deposition of sulphur compounds will occur over the entire Atlantic Region, due to the long range transport of sulphur compounds from other regions of North America.

Ultimately, the interpretation of site specific effects within the Atlantic Region, such as the increased acidity of a freshwater lake, may well be more readily linked to short periods of high deposition of sulphur from nearby sources, while major long term regional trends should be more closely associated with total annual deposition fluxes.

The purpose of this paper is to present information on anticipated changes in depositions of sulphur that will occur in the Atlantic Provinces as a result of an expansion in the use of coal for thermal power generation.

2. Current Levels of Sulphur Loadings to the Atlantic Provinces (1978)

Levels of sulphur emissions and depositions in the Atlantic Provinces in 1978 are shown in Table 1. The majority of the sulphur being deposited is from external sources, while the bulk (approximately 80%) of the sulphur emitted within any given province is 'exported' (i.e., not deposited within that provincial boundary). In addition, the data indicate that in 1978 all the Atlantic Provinces are currently net importers of sulphur compounds, as deposition fluxes are greater than emission fluxes.

In 1978, the Atlantic Provinces of Canada were considered to be 'moderate to low' emitters of SO_2 by comparison with other industrialized areas of the world. Emission fluxes from Great Britain and Germany are up to an order of magnitude greater, being 15.0 and 9.0 tonnes $S/km^2/yr$ respectively; while Norway and Sweden, who are considered to be low emitters of SO_2, have emission fluxes of 0.9 and 0.3 tonnes $S/km^2/yr$ respectively.

Rates of deposition of sulphur materials in the Atlantic Provinces are similar to those found in central Sweden and southern Norway (1.5 - 2.0 tonnes $S/km^2/yr$); and considerably lower than those found in central Europe and Great Britain (5 - 10 tonnes $S/km^2/yr$).

3. Changes in Sulphur Emissions and Depositions within the Atlantic Provinces Since 1978.

The calculation of changes in emissions and depositions presented are all made with the basic assumption that emissions and depositions from all sources have remained constant at their 1978 level, and that the only changes to be considered are those due to an increase in coal combustion for thermal power generation.

Since 1978, two major coal burning facilities have commenced operation within the region, these being Dalhousie # 2, New Brunswick, and

3. (continued)

Lingan #1 and #2, Nova Scotia. No SO_2 controls are installed at either of these facilities, and their emissions are accurately known. For the future (considered to be to the year 2,000), three alternatives for conversion to coal for power generation have been identified. (See Paper Design Criteria, Treatment Technology and Costs, where reasons for their selection as well as predicted changes in SO_2 emissions are given.) The first of these, Alternative A, includes the most probable conversions; the second, Alternative B, includes those conversions which are possible by virtue of their being technically feasible; while the third, Alternative C, includes those that are unlikely to occur other than with major modifications.

For each alternative, emissions (and subsequent depositions) were calculated for three levels of emission control; no SO_2 controls, maximum SO_2 emissions of 1.2 lb. SO_2 per 10^6 BTU of fuel, and maximum SO_2 emissions of 1.6 lb. SO_2 per 10^6 BTU of fuel. For convenience of comparison, all emissions and depositions were calculated per unit area (km^2), and are all expressed in terms of sulphur. The results are summarized in Table 2, and are illustrated in Figure 2. (The detailed information from which this table was prepared is shown in Appendix I.) Changes in depositions of sulphur compounds in Labrador have not been considered in this exercise, as these would be minimal and difficult to estimate. It can be assumed that such changes would be less than those experienced in Newfoundland.

4. Discussion

This study has shown that an expansion in the use of coal, without emission control, for the generation of power in Atlantic Canada will lead to major increases in SO_2 emissions and to significant increases in sulphur depositions within the Atlantic Provinces.

Since 1978, two major installations (Lingan 1 and 2, Dalhousie 1) have been commissioned without any SO_2 emission controls. This

4. (continued)

has resulted in substantial increases in SO_2 from Nova Scotia and New Brunswick (an increase of 25-30% on total provincial SO_2 emissions). Additional implementation of Alternatives A and B in turn without emission control would further increase SO_2 emissions in Nova Scotia and New Brunswick to a point where they would have doubled (88% and 113%, respectively, for Nova Scotia and New Brunswick) since 1978. The major point sources contributing to this increase will be Lingan in Nova Scotia, and Coleson Cove, Dalhousie and Grand Lake in New Brunswick.

On an absolute scale (using tonnes of sulphur emitted per unit area for comparison), in 1978 both Nova Scotia and New Brunswick were considered to be 'low to moderate' emitters of SO_2 in the industrialized world, with emission levels of approximately 1.5 tonnes S/km^2. Increased emissions between 1978 and 1980 have moved emission levels to 1.8-1.9 $tonnes/km^2$, a level no longer considered low but, at best, moderate. Further increases (Alternative A plus Alternative B) would raise emission levels in Nova Scotia and New Brunswick to 2.8 and 3.1 tonnes S/km^2 respectively, at which point these two provinces could be considered to be medium level emitters of SO_2 in the industrial world.

The applications of comtrols (to a level of 1.2 lb. $SO_2/10^6$ BTU or 1.6 lb. $SO_2/10^6$ BTU) would reduce emissions drastically. Again, considering the implementation of both Alternatives A and B with control, total provincial emissions would remain approximately constant at 1980 levels. Reduction of SO_2 emissions to 1978 levels would require major modifications of existing power generating facilities, or less total fossil fuel combustion.

It has been shown that the bulk (approximately 70-80%) of the SO_2 emitted from each of the Atlantic Provinces is exported (i.e., is not deposited in the province of origin); consequently, any increase in SO_2 emissions would not result in a commensurate increase in sulphur depositions. Increases in emissions would affect the province of origin most directly, but would also contribute to depositions of neighbouring provinces, particularly those "downwind" of the source.[2]

Once again, assuming the implementation of both Alternatives A and B with no controls, it is estimated that from 1978, the depositions of sulphur compounds would increase by the substantial amounts of 8%, 14% and 11% for Nova Scotia, New Brunswick, and Prince Edward Island respectively. In Newfoundland, it is estimated that under the same conditons, depositions would increase by 6%. The implementation of controls would allow depositions to remain close to their 1980 levels, but would be greater than the 1978 levels.

Finally, it is of some interest to observe that, in 1978, all of the Atlantic Provinces received substantially more sulphur per unit area than they emitted. In particular, Newfoundland and Labrador are virtual sinks for sulphur deposition. However, if emissions were to increase by the extent estimated by Alternatives A and B without SO_2 controls, then both New Brunswick and Nova Scotia would have SO_2 emissions (measured as sulphur) which exceed sulphur depositions, and would be net exporters of sulphur.

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[2] In the Atlantic Provinces, the prevailing winds are southwesterly and, in fact, for 50% of the time the wind is from the 90° sector WNW to SSW. Consequently, emissions from Nova Scotia and New Brunswick are carried directly over Prince Edward Island for a significant portion of the time.

APPENDIX I

Changes in Sulphur Emissions and Depositions in the Atlantic Region Since 1978 as a Result of an Expanded use of Coal in Thermal Power Generation.

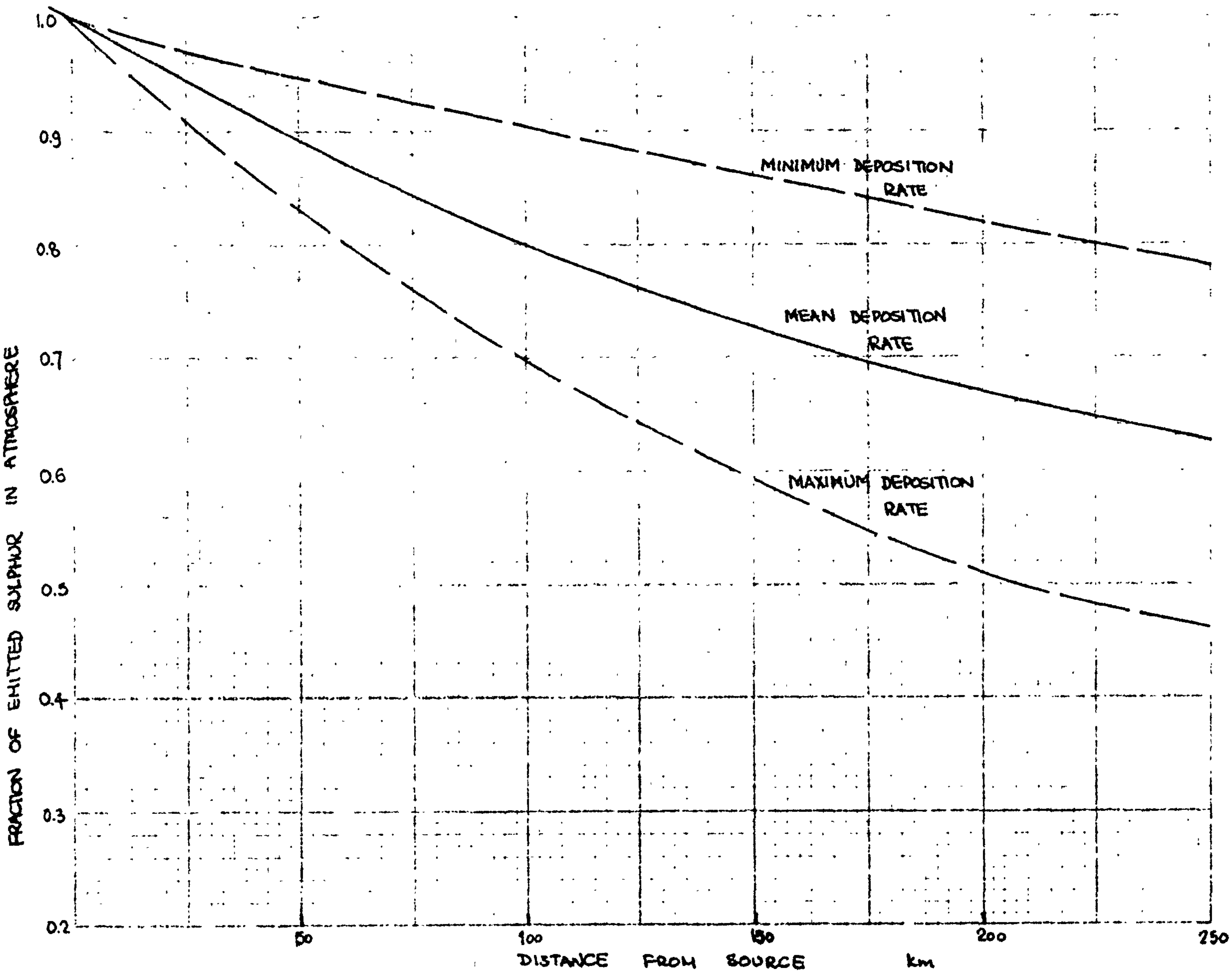
NOTES

1. Mean Annual Deposition Rates were used for all deposition calculations.

2. Labrador is not considered in this exercise; effects would be less than those experienced in Newfoundland.

3. Where incremental emissions (and depositions) are negative, i.e., where the introduction of controls upon conversion to coal at an existing facility would result in a net decrease of SO_2 emissions, all relevant data will be prefixed by a minus sign(-).

FIGURE 1:


1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
FRACTION OF EMITTED SULPHUR IN ATMOSPHERE
50
100
150
200
250
DISTANCE FROM SOURCE km
MINIMUM DEPOSITION RATE
MEAN DEPOSITION RATE
MAXIMUM DEPOSITION RATE

1980

STATION	WITHOUT SO_2 CONTROLS					WITH SO_2 CONTROLS				
	Increase in SO_2 Emmissions tonnes S/yr.	Increase in Sulphur Depositions tonnes S/year				Increase in SO_2 Emmissions tonnes S/yr.	Increase in Sulphur Depositions tonnes S/year			
		N.S.	N.B.	P.E.I.	Nfld.		N.S.	N.B.	P. E. I.	Nfld.
NOVA SCOTIA										
Lingan (1 & 2)	21,405	1,284	324	109	856	—	NOT APPLICABLE —			
NEW BRUNSWICK										
Dalhousie (1)	26,076	316	2,842	116	4,420	—	NOT APPLICABLE —			
TOTALS	47,481	1,600	3,166	225	5,176					

ALTERNATIVE A: MOST PROBABLE CONVERSIONS

STATION	WITHOUT SO_2 CONTROLS					WITH SO_2 CONTROLS TO 1.2 lb. $SO_2/10^6$BTU					WITH SO_2 CONTROLS TO 1.6 lb. $SO_2/10^6$BTU				
	Increase in SO_2 Emissions tonnes S/yr	N.S.	N.B.	P.E.I.	Nfld.	Increase in SO_2 Emissions tonnes S/yr	N.S.	N.B.	P.E.I.	Nfld.	Increase in SO_2 Emissions tonnes S/yr	N.S.	N.B.	P.E.I.	Nfld.
NOVA SCOTIA															
Lingan (3&4)	40,889	2453	620	209	1636	9117	547	138	47	364	12,126	728	184	63	494
Point Tupper (1A)	3,212	614	65	27	130	(-)1801	(-)343	(-) 36	(-)15	(-) 72	(-)1,321	(-)253	(-) 26	(-)11	(-)52
Tufts Cove (1)	3,599	838	98	32	119	(-)2015	(-)467	(-) 55	(-)19	(-) 67	(-)1,478	(-)343	(-) 40	(-)14	(-)149
TOTALS	47,700	3905	783	268	1885	5301	(-)263	47	12	225	9,327	132	118	38	383
NEW BRUNSWICK															
Grand Lake	26,085	552	7434	245	521	2571	54	810	27	55	3,428	72	1080	36	74
TOTALS	73,785	4457	8217	513	2406	7872	(-)209	857	39	280	12,755	205	1198	74	457

ALTERNATIVE B: MOST PROBABLE CONVERSIONS

STATION	WITHOUT SO_2 CONTROLS					WITH SO_2 CONTROLS TO 1.2 lb. $SO_2/10^6$BTU					WITH SO_2 CONTROLS TO 1.6 lb. $SO_2/10^6$BTU				
	Increase in SO_2 Emissions tonnes S/yr	Increase in Sulphur Depositions tonnes S/yr				Increase in SO_2 Emissions tonnes S/yr	Increase in Sulphur Depositions tonnes S/yr				Increase in SO_2 Emissions tonnes S/yr	Increase in Sulphur Depositions tonnes S/yr			
		N.S.	N.B.	P.E.I.	Nfld.		N.S.	N.B.	P.E.I.	Nfld.		N.S.	N.B.	P.E.I.	Nfld.
NOVA SCOTIA NIL															
NEW BRUNSWICK Coleson Cove (1, 2 & 3)	53,286	2274	7949	408	772	(-)5070	(-)253	(-)887	(-)46	(-) 86	773	38	132	7	13
Dalhousie (1)	12,775	155	1392	57	2165	(-) 680	(-) 8	(-) 76	(-) 6	(-)115	(-)181	(-)2	(-)20	(-)2	(-)31
TOTAL	66,061	2429	9341	465	2937	(-)5750	(-)261	(-)963	(-)52	(-)201	(-)672	36	112	5	(-)17

ALTERNATIVE C: INCLUDES CONVERSIONS WHICH ARE UNLIKELY

STATION	WITHOUT SO_2 CONTROLS					WITH SO_2 CONTROLS					WITH SO_2 CONTROLS				
	Increase in SO_2 Emissions tonnes S/yr	Increase in Sulphur Depositions tonnes S/yr				Increase in SO_2 Emissions tonnes S/yr	Increase in Sulphur Depositions tonnes S/yr				Increase in SO_2 Emmissions tonnes S/yr	Increase in Sulphur Depositions tonnes S/yr.			
		N.S.	N.B.	P.E.I.	Nfld.		N.S.	N.B.	P.E.I.	Nfld.		N.S.	N.B.	P.E.I.	Nfld.
NOVA SCOTIA															
Point Tupper (1B&2)	8032	1535	163	68	325	(-)4503	(-)857	(-)90	(-)38	(-)180	(-)3303	(-)633	(-)65	(-)28	(-)130
Tufts Cove (2&3)	9003	2096	245	80	298	(-)5039	(-)1168	(-)138	(-)48	(-)168	(-)3696	(-)858	(-)100	(-)35	(-)123
TOTALS	17,035	3631	408	148	623	(-)9542	(-)2025	(-)228	(-)86	(-)348	(-)6999	(-)1491	(-)165	(-)63	(-)253
NEW BRUNSWICK															
Courtney Bay (1,2,3,&4)	13,436	677	2350	136	230	(-)1683	(-) 85	(-)294	(-)169	(-)31	227	11	40	23	4
NEWFOUNDLAND															
Holyrood (1,2,3,&4)	20,607	71	71	14	2056	(-)1814	(-) 6	(-) 6	(-) 1	(-)181	(-)812	(-)3	(-)3	(-)1	(-)81
TOTALS	51,078	4379	2829	298	2909	(-)13,049	(-)2116	(-)528	(-)256	(-)560	(-)7584	(-)1482	(-)128	(-)41	(-)330

TABLE 1: CONTRIBUTION OF LOCAL SOURCES TO THE DEPOSITION OF SULPHUR WITHIN THE ATLANTIC PROVINCES: 1978

PROVINCE	TOTAL SO_2 EMISSIONS[1]				SULPHUR DEPOSITIONS			
	Tonnes SO_2 per year	Tonnes S per year	Emission Rate Tonnes S/km^2 per year	% Export	Depositions of Local Origin Tonnes S/yr	Total Deposit Tonnes S/yr	Total Sulphur Deposits of Local Origin %	Deposition Rate Tonnes S/km^2/yr
NOVA SCOTIA	156,679	78,340	1.48	78	17,200	100,500	17	1.90
NEW BRUNSWICK	210,775	105,388	1.47	79	22,100	137,800	16	1.93
P.E.I.	10,823	5,412	0.95	90	540	9,800	6.5	1.73
NEWFOUNDLAND	43,617	21,808	0.21	74	56,000	137,900	4.1	1.31
LABRADOR	4,294	2,147	0.008	56	9,500	284,000	0.3	1.08

1. Data based on estimates for 1978, and includes all sources

TABLE 2:

SUMMARY OF EMISSIONS AND DEPOSITIONS OF SULPHUR IN THE ATLANTIC REGION SINCE 1978 AS A RESULT OF AN INCREASED COMBUSTION OF COAL FOR POWER GENERATION.

NOTE: All units are as TONNES SULPHUR / KM^2 / YEAR

A. EMISSIONS

PROVINCE	SO_2 EMISSIONS		ESTIMATED FUTURE EMISSIONS								
			ALTERNATIVE A			ALTERNATIVE B			ALTERNATIVE C		
	1978	1980	WITHOUT CONTROLS	CONTROLS TO 1.2 lb. $SO_2/10^6$ BTU	CONTROLS TO 1.6 lb. $SO_2/10^6$ BTU	NO CONTROLS	CONTROLS TO 1.2 lb. $SO_2/10^6$ BTU	CONTROLS TO 1.6 lb. $SO_2/10^6$ BTU	NO CONTROLS	CONTROLS TO 1.2 lb $SO_2/10^6$ BTU	CONTROLS TO 1.6 lb. $SO_2/10^6$ BTU
NOVA SCOTIA	1.48	1.89	2.79	1.99	2.06	2.79	1.99	2.06	3.11	1.81	1.93
NEW BRUNSWICK	1.47	1.84	2.20	1.87	1.89	3.13	1.79	1.88	3.32	1.77	1.88
NEW-FOUNDLAND	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.40	0.19	0.20

B: DEPOSITIONS:

PROVINCES	SO_2 DEPOSITIONS		ESTIMATED FUTURE DEPOSITIONS								
			ALTERNATIVE A			ALTERNATIVE B			ALTERNATIVE C		
	1978	1980	WITHOUT CONTROLS	CONTROLS TO 1.2 lb. $SO_2/10^6$ BTU	CONTROLS TO 1.6 lb. $SO_2/10^6$ BTU	NO CONTROLS	CONTROLS TO 1.2 lb. $SO_2/10^6$ BTU	CONTROLS TO 1.6 lb. $SO_2/10^6$ BTU	NO CONTROLS	CONTROLS TO 1.2 lb $SO_2/10^6$ BTU	CONTROLS TO 1.6 lb. $SO_2/10^6$ BTU
NOVA SCOTIA	1.90	1.93	2.01	1.93	1.93	2.06	1.92	1.93	2.14	1.88	1.91
NEW BRUNSWICK	1.93	1.97	2.09	1.98	1.98	2.22	1.97	1.98	2.26	1.96	1.97
P.E.I.	~~1.73~~	~~1.77~~	1.86	1.78	1.78	1.94	1.77	1.78	2.00	1.72	1.77
NEW-FOUNDLAND	1.31	1.35	1.37	1.35	1.35	1.40	1.35	1.35	1.43	1.34	1.35

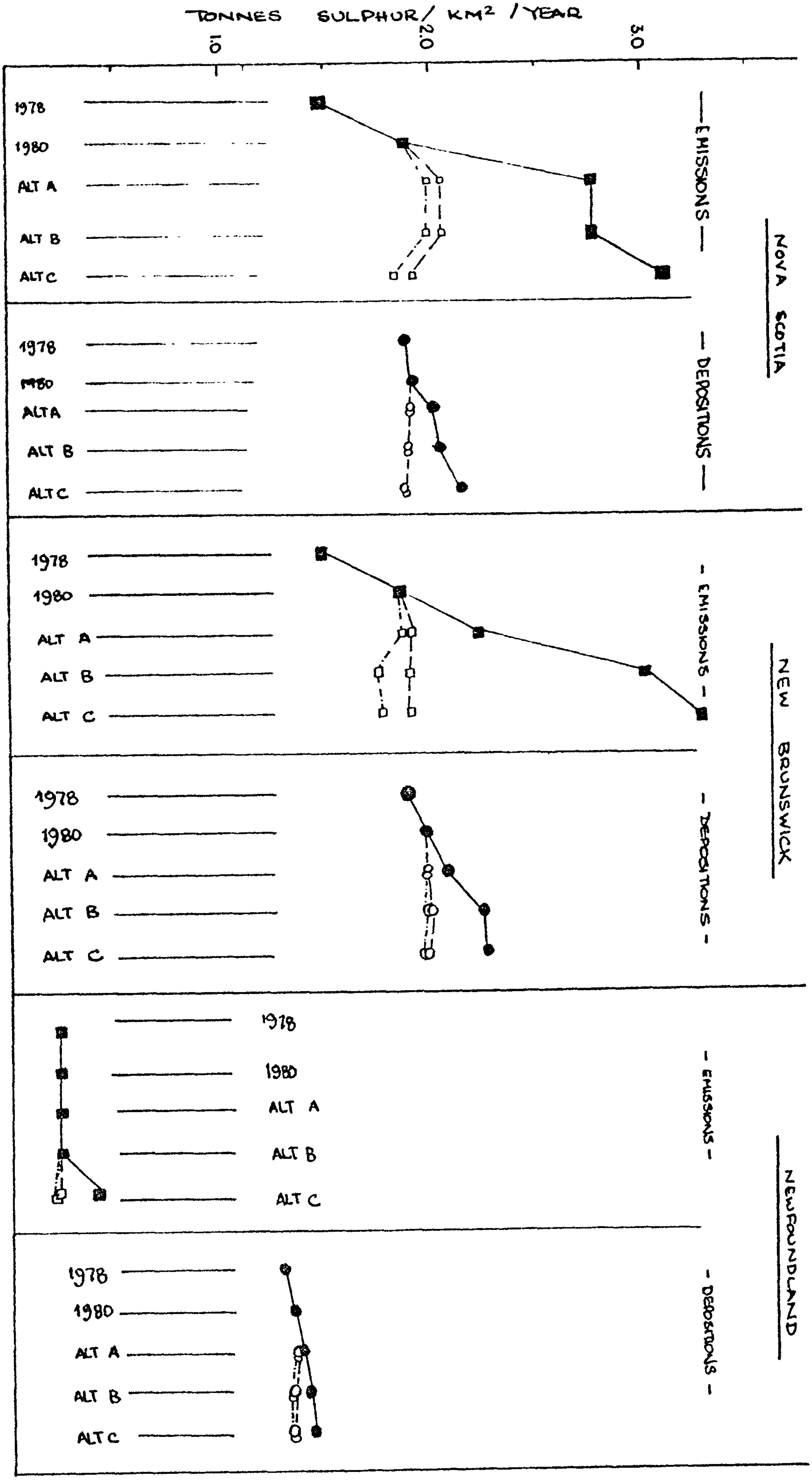
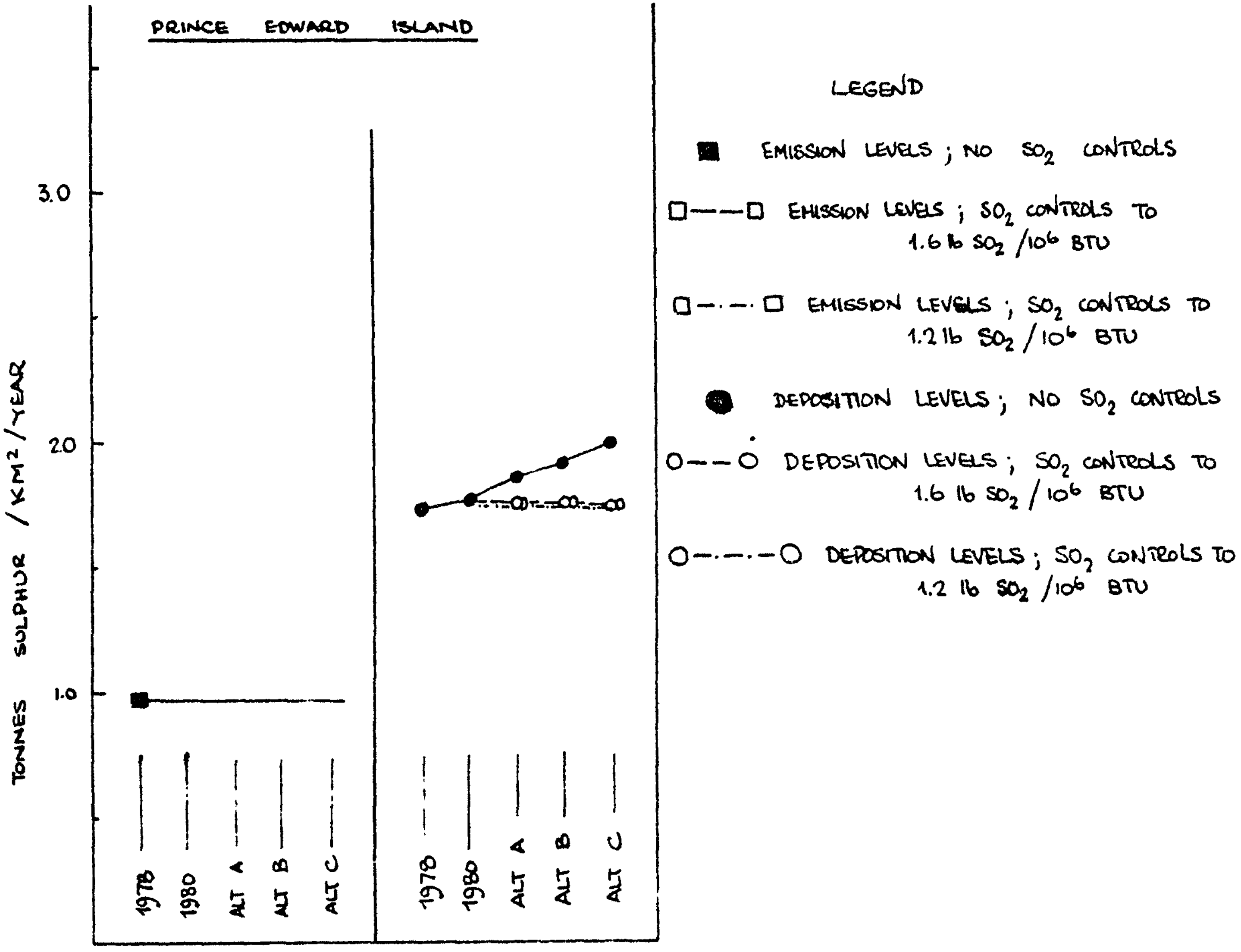


FIGURE 2: EMISSIONS OF SO_2 AND DEPOSITIONS OF SULPHUR IN THE ATLANTIC PROVINCES

FIGURE 2 (cont.)



DESIGN CRITERIA, TREATMENT TECHNOLOGY AND COSTS

by K. HAMILTON

The Steam-Electric Power Industry In The Atlantic Region

Electrical power in the Atlantic Region is generated from hydro resources, by fossil fuel combustion, and within the near future, through nuclear fission at Point Lepreau. In the Maritime Provinces and in Nova Scotia in particular, the great amount of local electrical power demand is met through generation at oil and coal-fired thermal-electric stations (Table 1). It is these stations and their emission into the ambient air of oxides of nitrogen and sulphur, particulate matter, heavy metals, etc., that have caused recent concern in our Region. Not only can these installations lead to a localized air quality problem, but they also contribute in a significant way, as has been shown above, to the "acid rain" problem.

Expansion of the coal-fired capacity through the installation of new coal-fired units, together with the possible conversion of a number of existing oil-fired plants to coal, has led to added concern.

Design Criteria

For the purpose of this document, it has been assumed that the Atlantic Canada contribution to the "acid rain" problem can be kept at acceptable levels (and defensible levels from a Canada - U.S. negotiating stance) through the control at source of SO_2 emissions.

One can suggest numerous alternatives for establishing an acceptable emission rate for generating facilities. One could use the U.S. E.P.A. New Source Performance Standards (1979) (1.2 lb. of $SO_2/10^6$ Btu heat imput to boilers), proposed DOE Thermal Power Guidelines (1.6 lb. of $SO_2/10^6$ Btu), requirements derived from an evaluation of acceptable environmental effects or some other number related to the capability of control technology.

In this document, we shall assume that any new thermal electric station or expansion of any existing station will be required to either meet the U.S. E.P.A. SO_2 emission rate level of 1.2 lb./10^6 Btu heat imput or the proposed but less stringent DOE Thermal Power Guideline of 1.6 lb. of $SO_2/10^6$ Btu. In addition, we shall assume that any oil to coal conversion will also be required to meet either of these emission rates. Furthermore, we shall assume that most existing oil-fired generating stations in the Atlantic Region could be converted. Costing will be based on these assumptions. Several generating stations, e.g., Water Street, Maritime Electric and Chatham will not be considered because of their small size and/or age.

One should be aware that for various reasons, it may prove prohibitively costly to carry on conversions to a number of the existing generating facilities. Before decisions on conversions could be made, detailed engineering feasibility studies would have to be carried out by the utility sector. A major consideration for utility planners would be the loss of power plant availability during construction periods.

While new facilities or modifications to existing facilities would require appropriate particulate matter and NO_x air emission control and certainly control of liquid discharges, particularly the metals in these discharges, consideration will not be given to these aspects in this report. We have assumed that the emission of sulphur dioxide is the major contributing factor to the "acid rain" problem. At this time, much less is known about NO_x emission contribution to the problem.

SO_2 Emission Rates

Annual mass emissions of SO_2 for new thermal stations with and without SO_2 controls (controlled to 1.2 or 1.6 lb./10^6 Btu) are given in Table 2. The definition of new installations needs some consideration in that electric utility officials would contend that anything that is presently on the drawing board is no longer new, since decisions on equipment supply, siting, etc., have already been made. Utilities in our Region plan typically 6-8 years in advance. For the purposes of this document, we shall assume that installations commissioned past 1983 will be considered new. The year 2000 is thought to be as far into the future as we should presently predict due to various considerations such as the nuclear/fossil-fired mix, likelihood of additional power pooling, possibility of future purchases of large blocks of power from Quebec, other sources of power such as tidal, availability of natural gas in the future, etc.

Table 2 also gives annual mass emissions of SO_2 for existing oil-fired thermal stations as well as for these same stations after conversion to coal-firing and subsequent application of SO_2 control at source. In addition, an indication is given of the potential for conversion to coal based on a consideration of existing boiler design, ease of installation of auxiliaries (need for pulverizers, coal and ash handling systems, etc.).

It is assumed that coal fired at these new and "converted" stations will be high in sulphur (up to 7% in New Brunswick and 3.5% in Nova Scotia). For column 2 in Table 3, which indicates present estimated emissions on oil without controls for SO_2, we have made estimations of 1980 emissions based on historical fuel consumption data. For the remainder of the columns in this table, a capacity factor of 70% was assumed which is considered to be representative of plant use, both for new stations and newly "converted" (to coal) stations. These assumptions do have weaknesses in that a station use factor will obviously change with age (and therefore efficiency of equipment), and in this case, most certainly because of the conversion of oil to coal itself.

Sulphur Dioxide Control Technology

General

The control at source of sulphur dioxide from thermal power plants (coal and oil-fired) can be achieved by treating the fuel to remove the sulphur prior to combustion, by the injection or use of certain reactive agents into the combustion zone, and by treating the flue gas after it has left the boiler unit (FGD systems). Many processes have been advanced as alternatives for solution of the sulphur dioxide emission problem, some of which are still at the research stage, others having been developed to the point where they are operating on conventional generating units.

The FGD systems most commonly in use at the present time are lime/limestone scrubbers of various proprietary designs, located in the U.S.A. or Japan. American units of this type are predominantly of the "throwaway" kind; that is, they do not attempt to reclaim any of the reagents, nor do they make a useful by- product.

Table 3 outlines the various alternatives for SO_2 control, indicates the pollutant reduction efficiency and shows the time frame of applicability.

Alternate energy sources such as nuclear power, natural gas, hydroelectric power, solar energy, etc., will, for obvious reasons, reduce requirements for coal and oil combustion and in so doing, reduce the emission loading of SO_2.

Low Sulphur Coal

Use of low-sulphur coal is one approach to controlling the sulphur emissions from coal-fired power plants. Most of the low-sulphur coal reserves in North America are in the western regions of Canada and the U.S. Maritime coals are almost always greater than 2% in sulphur; fuels from the Minto coal field average above 5% sulphur content. Substantial quantities of coal less than 1.5% do not exist in the Atlantic Region. Tables 4 and 5 outline present reserves and characteristics of coals in the Atlantic Region.

Many of the low-sulphur western coals are also low in heat content. This, together with distances involved, makes the transportation costs of western fuels to our Region prohobitively expensive.

Coal Cleaning

Established methods of crushing and washing/separating (physically cleaning) coal can remove a significant amount of sulphur at the mine. The "cleanability of a coal depends on its composition. Coal washing can remove only the "free" sulphur which occurs as ferric sulphide Fe S, in the form of pyrites or marcanite. The ratio of free to organic sulphur varies widely from one coal to another.

Coal washing can be carried out by both dry techniques (air washing) or most commonly through wet methods (dense media, froth flotation, mechanically) .

The applicability of these techniques to coals in the Atlantic Region should be investigated further. Work is presently being carried on in this area by the federal Department of Energy, Mines and Resources, provincial Department of Mines, various research councils, universities, etc.

Chemical Coal Cleaning

These techniques have yet to be demonstrated commercially; they are reported to have the potential to remove virtually all pyrite sulphur and much of the organic sulphur as well.

Several of these are listed; they include ferric ion leaching, organic solvent leaching, and alkaline leaching.

Flue Gas Desulphurization

The most promising sulphur-control technology to date has been flue gas desulphurization. F.G.D. processes fall roughly into two classes, recovery and non-recoverable types. The former have the feature of re-using the reagents, which are employed to isolate the sulphur, by recycling them back to the system. The latter rejects the spent reagents as a waste product, which must be removed from the power plant flue gas cleaning system and disposed of in an environmentally acceptable manner; for this reason, they are often called "throw away" systems. The "throw away" systems have proved most successful to date. They also, of course, can lead to water pollution problems if effluents (sludges) are not treated properly.

Table 6 lists costs (U.S. E.P.A. - 1977) associated with various F.G.D. systems for a typical 500 MW electrical generating station.

Table 7 outlines the status of scrubber technology in the U.S. as of December, 1979.

Coal Liquefaction

By artifically increasing its hydrogen content, coal can be converted to liquid fuels. The process allows the removal of sulphur and ash.

Coal liquefaction will not be generally applicable for a number of years on a large scale for both economic and technical reasons.

Coal Gasification

Coal gasification is not a novel concept, as coal has been converted to "town gas" for decades. A more efficient technique, the Lurgi process is presently in commercial use. In recent years, much research into various techniques for gasification has been initiated to improve conversion efficiency. Several of the most promising techniques are the "Hygas" process and the"Cogas" process.

Fluidized Bed Combustion

For acceptable performance, coal-fired boiler and emission control designs are closely tied to the combustion properties of specific coals and to their nitrogen, ash and sulphur content. Fluidized bed combustion may be a way to reduce these dependencies. Fluidized by forced air, the burning of coal in the presence of added limestone yields heat at temperatures low enough to suppress NO_x formation and allow sulphur capture by the limestone.

Utility demonstration boilers are to be built in the U.S. and Canada in the early 1980's. It is likely that the design will be available in the post 1990 period for full scale application to the utility industry.

Present Option for Control

Practicable options for sulphur dioxide emission control over the next 10 year period in our Region for the utility sector would appear to be limited to:

(1) Modification of fuel characteristics physical coal cleaning (PCC) or the substitution of lower sulphur coal for higher sulphur coals and residual oils.

and (2) Flue gas treatment-limestone scrubbing flue gas desulphurization (FGD).

It is possible that both physical coal cleaning and FGD could be used at a given generating station to meet a required emission rate. It is likely that for the case of very high sulphur coal such as that from the Minto field, both techniques would have to be used.

In the 1990-2000 period, application of a number of the emerging technologies will be likely. For the sake of simplicity in this study, these technologies will not be considered in the cost analysis.

Costs of SO_2 Controls for Thermal Electric Stations in the Atlantic Region

Costs of SO_2 control for the various new coal-fired stations, both new construction and newly converted from oil to coal, are shown in Tables 8 and 9. These cost figures are based on a Canadian Electrical Association (C.E.A.) Research Report (78-98) entitled Air Emission Control Options - Canadian Utility Cost Impacts. A detailed description of the derivation of these figures can be found in that report. The C.E.A. cost analysis is based for the most part on the Tennessee Valley Authority and Pedco cost models for limestone slurry systems. The general level of accuracy of the C.E.A. figures is approximately ±20%. Costs are shown for controls to meet either the 1.2 lb. of $SO_2/10^6$ Btu or 1.6 lb. of $SO_2/10^6$ Btu emission limits.

Table 8 presents total depreciable investment in terms of 1979 dollars and includes both direct investment and indirect capital items. Examples of direct investment are materials and labour for equipment and services, utilities, foundations, etc. Examples of indirect capital items include engineering design, contractor fees, contingencies, construction expense, interest during construction, etc. The three most important direct cost factors are plant size, sulphur removal rate and flue gas flow rate. Table 1 also indicates depreciable investment in terms of dollars per net kilowatt of installed electrical capacity for each station listed.

Table 9 depicts annual operating costs and should be appropriate for the base loaded case (above 50% capacity factor) in the 1991-2000 year period. Here again the most important cost factors are sulphur removal rates, flue gas flow rates and plant size. The first two types of costs are, however, also affected by hours of plant operation. For example, if the plants noted were to be operated either in an intermediate or peaking mode, the annualized cost figures would be substantially higher.

By September, 1980, the Air Pollution Control Directorate of the Environmental Protection Service will have completed a number of studies which will provide additional detailed information on costs of such controls.

TABLE 1 - FOSSIL FUEL-FIRED THERMAL ELECTRIC STATIONS IN ATLANTIC CANADA

GENERATING STATION	NO. OF UNITS SIZE (MW)	FUEL FIRED
New Brunswick:		
Coleson Cove	3 x 372 MW	Oil
Dalhousie	1 x 112 MW	Oil
	1 x 200 MW	Coal (Minto)
Courtenay Bay	1 x 14 MW	Oil
	1 x 54 MW	Oil
	2 x 106 MW	Oil
Grand Lake	1 x 64 MW	Coal (Minto)
	1 x 200 MW (1990)	
Nova Scotia:		
Lingan	2 x 150 MW	Coal (Cape Breton)
	2 x 300 MW (1986)	Coal (Cape Breton)
Glace Bay	1 x 15 MW	Coal/Oil
	2 x 17 MW	Coal/Oil
Point Tupper	1 x 65 MW	Oil
	1 x 150 MW	Oil
Tufts Cove	2 x 100 MW	Oil
	1 x 150 MW	Oil
Trenton	1 x 20 MW	Coal (Cape Breton)
	1 x 150 MW	Coal (Cape Breton)
Water Street	1 x 45 MW	Oil

TABLE 1 - Continued

GENERATING STATION	NO. OF UNITS SIZE (MW)	FUEL FIRED
Prince Edward Island:		
Maritime Electric	1 x 10 MW	Oil
	2 x 20 MW	Oil
Newfoundland:		
Holyrood	3 x 150 MW	Oil
	1 x 150 MW (1984)	

Excluding Units Commissioned before 1958

Unit Sizes are in Gross Megawatts

TABLE 2 - SULPHUR DIOXIDE EMISSIONS (SHORT TONS/YEAR)

GENERATING STATION	PRESENT ESTIMATED EMISSION RATE ON OIL (WITHOUT SO_2 CONTROL)	FUTURE ESTIMATED EMISSIONS RATE ON COAL (WITHOUT SO_2 CONTROL)	FUTURE ESTIMATED EMISSIONS WITH CONTROLS TO MEET 1.2 lb/10^6 BTU	SIMILARLY 1.6 lb/10^6 BTU
Lingan 3 & 4 (600 MW)*	---	90,140	20,080	26,800
Grand Lake (212 MW)*	---	57,520	5,670	7,560
Point Tupper - Units 1A*) (210 MW) 1BΔ) 2Δ)	25,000	49,790	11,100	14,800
Tufts Cove - Units 1* (100 MW) (350 MW) 2Δ (100 MW) 3Δ (150 MW)	27,990	55,770	12,440	16,580
Coleson Cove - Units 1†) (1050 MW) 2†) 3†)	47,300	164,800	36,720	48,960
Dalhousie - Unit 1 † (112 MW)	4,731	33,900	3,250	4,300
Courtenay Bay - Units 1Δ) (280 MW) 2Δ) 3Δ) 4Δ)	12,280	42,900	9,570	12,750
Holyrood - Units 1Δ) 2Δ) 3Δ) 4Δ)	18,270	63,700	14,200	16,580

* Currently planned coal fired plant or probable conversion to coal.
† Possible conversion.
Δ Unlikely conversion.

TABLE 3 - CONTROL OF SO FROM UTILITY SIZED BOILER UNITS

SO CONTROL TECHNOLOGY	POLLUTANT REDUCTION EFFICIENCY (%)	TIME FRAME OF APPLICABILITY
Flue Gas Desulphurization	80 - 95	Current (new and existing)
Physical Coal Cleaning	20 - 40	Current
Chemical Coal Cleaning	10 - 60	Post - 1990
Use of Low Sulphur Coal	---	Current (limited availability)
Fluidized Bed Combustion (with Chemical Sorbent)	80 - 90	Post - 1990 (widely applicable)
Coal Gasification Low BTU	90 - 95	Post - 1985 (more applicable to new units)
Coal Gasification High BTU	90 - 95	Post - 1990 (new and existing units - high costs)
Coal Liquefaction	90 - 95	Post - 1990 (new and existing units)

Source: Modified from USEPA Decision Series Publication - EPS - 600/9-77-041

TABLE 4 - PRODUCTION AND REMAINING RESOURCES OF COALFIELDS IN THE MARITIMES (AFTER HACQUEBARD, 1977)

COALFIELD	TYPE OF MINE	PRODUCTION FROM 1785-1975 (MILLION TONS)	RESOURCES	
			DEMONSTRATED (MILLION TONS)	INFERRED (MILLION TONS)
1. Minto, N.B.	Surface	30	19	-
2. Lake Stream, N.B.	Underground	-	10	-
3. Beersville, N.B.	Underground	-	20	-
4. Joggins-Chignecto, N.S.	Underground	7	7	6
5. Springhill, N.S.	Underground	36	8	26
6. Debert, N.S.	Underground	-	4	-
7. Pictou, N.S.	Underground	59	63	8
<u>Individual Seams</u>:				
A. McLeod			2	
B. McGregor			3	
C. Foord			8	4

TABLE 4 - (CONTINUED)

COALFIELD	TYPE OF MINE	PRODUCTION FROM 1785-1975 (MILLION TONS)	RESOURCES	
			DEMONSTRATED (MILLION TONS)	INFERRED (MILLION TONS)
D. New Seam			3	
E. Scott			28	2
F. Acadia			17	2
G. Third			2	
8. Port Hood, N.S.	Underground	1	27	9
9. Mabou, N.S.	Underground	-	9	134
10. Inverness, N.S.	Underground	8	-	-
11. St. Rose-Chimney Corner, N.S.	Underground	1	13	-
12. Sydney, N.S.	Underground	327	843	555
Individual Seams:				
A. Sydney Mines			224	220
B. New Waterford			291	86
C. Reserve of #26 Colliery			120	
D. Donkin			76	221
E. Port Morien			132	78

Demonstrated - Measured Geologically
Inferred - Predicted on the basis of statistics and analysis of similar formations.

Source: EPS-5-AR-79-5

TABLE 5 - ANALYSIS OF COALS IN ATLANTIC CANADA (MONTGOMERY AND ANDERSON, 1972)

REGION	CALORIFIC VALUE DRY BTU/LB GROSS	MOISTURE %	ASH %	VOLATILE MATTER %	FIXED CARBON	SULFUR %
New Brunswick	12930 (± 439)	2.5 (± 2.7)	14.5 (± 2.3)	33.1 (± 2.2)	49.7 (± 2.1)	6.1 (± .9)
Nova Scotia	13406 (± 1203)	3.4 (± 2.1)	11.5 (± 7.2)	32.5 (± 3.9)	52.9 (± 3.9)	1.8 (1.3)

Source: EPS-5-AR-79-5

TABLE 6 - COST ASSOCIATED WITH VARIOUS F.G.D. SYSTEMS FOR A 500 MW PLANT

PROCESS	ENERGY PENALTY % OF PLANT OUTPUT	CAPITAL COSTS $/KW	ADDED OPERATING COSTS MILS/KWH
Lime	3-5%	87	4.7
Limestone	3-4%	97	4.0
Double Alkali	3-5%	101	4.2
Magnesium Oxide	7-8%	101	5.2
Wellmanlord	7-8%	113	5.9

Source: U.S. EPA - 600/9-77-041

TABLE 7 - NUMBER AND TOTAL CAPACITY OF F.G.D. SYSTEMS IN THE U. S. (DECEMBER, 1979)

STATUS	NO. OF UNITS	TOTAL CONTROLLED CAPACITY MW	EQUIVALENT SCRUBBED CAPACITY MW
Operational	62	23,297	21,510
Under Construction	39	17,270	16,051
Planned:			
Contract Awarded	23	11,949	11,651
Letter of Intent	2	842	842
Requesting/Evaluating Bids	15	11,131	10,281
Considering only F.G.D. Systems	35	20,022	19,902
TOTAL	176	84,511	80,237

Total Controlled Capacity (TCC) is the summation of the gross unit capacities (MW) brought into compliance with F.G.D. systems regardless of the percent of the flue gas scrubbed by the F.G.D. system(s).

Equivalent Scrubbed Capacity (ESC) is the summation of the effective scrubbed flue gas in equivalent MW based on the percent of the flue gas scrubbed by the F.G.D. system(s).

SO_2 CONTROL COSTS

TABLE 8

Generating Station		Total Depreciable Investment (million $ 1979)		Depreciable Investment $ /Kw of Net Installed	
		1.2 lb SO_2/ 10^6 Btu^2	1.6 lb SO_2/ 10^6 Btu^2	1.2 lb SO_2/ 10^6 Btu^2	1.6 lb SO_2/ 10^6 Btu^2
Lingan	Unit 3 - 288 MW	26.5	23.1	92.1	80.3
	4 - 288 MW	26.5	23.1	92.1	80.3
Grand Lake New Unit	- 200 MW	47.3	47.3	236.4	236.4
Point Tupper	Unit 1A- 90 MW	9.9	9.5	110.6	96.2
	1B- 90 MW	9.9	9.5	110.6	96.2
	2 - 144 MW	15.9	13.9	110.6	96.2
Tufts Cove	Unit 1 - 96 MW	10.6	9.2	110.6	96.2
	2 - 96 MW	10.6	9.2	110.6	96.2
	3 - 144 MW	15.9	13.9	110.6	96.2
Dalhousie	Unit 1 - 105 MW	24.8	24.8	236.4	236.4
Courtenay Bay	Unit 1 - 50 MW	5.5	4.8	110.6	96.2
	2 - 13 MW	1.4	1.3	110.6	96.2
	3 - 100 MW	12.2	9.6	110.6	96.2
	4 - 100 MW	12.2	9.6	100.6	96.2
Coleson Cove	Unit 1 - 350 MW	38.7	33.6	110.6	96.2
	2 - 350 MW	38.7	33.6	110.6	96.2
	3 - 350 MW	38.7	33.6	110.6	96.2
Holyrood	Unit 1 - 141 MW	15.6	13.5	110.6	96.2
	2 - 141 MW	15.6	13.5	110.6	96.2
	3 - 141 MW	15.6	13.5	110.6	96.2
	4 - 141 MW	15.6	13.5	110.6	96.2

---

1. Lingan units 3 and 4 and a new unit at Grand Lake are likely to be constructed in the 1985 - 90 period. It is certain that these will be coal fired stations.
2. Point Tupper, Tufts Cove, Dalhousie #1, Courtenay Bay, Coleson Cove, and Holyrood are candidates for coal to oil conversions, some stronger condidates than others. Costs listed are for SO_2 controls applied to these stations after the conversion to coal has taken place.

3. Costs are shown for the installation of controls to meet both the 1.2 lb $SO_2/10^6$ Btu and 1.6 lb of $SO_2/10^6$ Btu emission limits.

4. For both the new unit at Grand Lake and the converted Dalhousie #1 Unit, which would likely burn high sulphur Minto coal, it is unlikely FGD alone would allow either the 1.2 lb or 1.6 lb/10^6 Btu limits to be met. An additional reduction through coal cleaning would have to be achieved and this at additional cost. These costs are not presently known.

5. Point Tupper Units 1A and 1B are approximately equivalent to the sizes in terms of megawatts shown. These two units, however, provide steam for process heating rather than electric power

6. It is assumed that Lingan, Point Tupper, Tufts Cove, Courtenay Bay and Coleson Cove would use Cape Breton Coal.

TABLE 2

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                              H-COAL LP MODEL
                      REPORT 2 - ECONOMICS SUMMARY

---Case Number: 1
   Study Title:  H-Coal LP Model Validation
   Case Description:  Distillate Fuel Oil Production
---Coal Feed Type:   Illinois #6

   Plant Location:  Illinois                     BASE_CASE
   Plant Startup Year: 1979

   Investments                                    M$       Operating Costs                   M$/Year
   Coal Preparation and General Offsites        133.8      Feed Coal 20.00 S/ST               167.1
   H-Coal Liquefaction                          334.9      Purchased Power 3.0 Cents/KWH        0.0
   Hydrogen Manufacture                         281.0      Raw Water 40 Cents/KGAL              2.4
   Hydrogen Compression                          17.6      Catalyst and Chemicals              22.4
   Oxygen                                       152.6      Labor, Supervision and Overhead     15.9
   Treating and Recovery                         75.1      Maintenance                         48.0
   Utilities                                    275.6      Capital Changes                    428.0
   Tankage/Product Sales                         60.2
   TOTAL ERECTED COST                          1330.9      TOTAL ANNUAL COSTS                          702.4
   Catalyst and Chemicals                         9.4
---Interest on Constr. Loan                     177.3
   Taxes and Insurance                           36.6      REVENUES                          M$/Year
---TOTAL CAPITAL REQUIREMENT                   1554.2      LIQUID PRODUCTS
                                                           C3 LPG               15.39 $/B       29.5
                                                           C4 LPG               17.42 $/B       26.3
                                                           C5/400 F Naphtha     28.41 $/B      357.7
                                                           400/650 F Fuel Oil   28.40 $/B      229.3
                                                           650/975 F Fuel Oil   28.40 $/B       19.6
                                                           975+ F Fuel Oil            $/B
                                                           TOTAL                26.73 $/B      662.4

                                                           BY PRODUCTS
                                                           C1/C2 Gas             2.00 $/MBTU    10.6
                                                           Ammonia             130.00 $/ST      10.5
                                                           Sulfur               15.00 $/LT       3.8
                                                           TOTAL                                24.9

                                                           TOTAL REVENUES                              687.3

                                                           NET CASH FLOW                               -15.1
   Note: (1) K = Thousands, M = Millions, G = Billions
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TABLE 3

COGAS PROCESS
TOTAL PLANT INVESTMENT
250 BILLION BTU/DAY PIPELINE GAS
MID-1979 DOLLARS

COAL PROCESS DESCRIPTION	PITTSBURGH SEAM $MM	WESTERN SUBBITUMINOUS $MM	ILLINOIS NO. 6 SEAM $MM
COAL UNLOADING AND HANDLING	14.6	N.A.	17.3
COAL PREPARATION	49.3		58.6
PYROLYSIS AND GASIFICATION	241.9		207.0
OIL RECOVERY AND TREATMENT	135.5		143.1
GAS PURIFICATION	51.5		59.4
HYDROGEN GENERATION	21.3		27.8
SHIFT AND METHANATION	32.5		32.6
BULK CO_2 REMOVAL & GAS COMPRESSION	26.9		27.4
GAS DEHYDRATION	0.5		0.5
FLUE GAS POWER RECOVERY	160.2		169.0
SO_2 REMOVAL	37.0		41.8
SULFUR RECOVERY	37.0		47.1
AMMONIA RECOVERY	4.0		5.3
THERMAL OXIDIZER & FLARE	4.0		4.4
OFF-SITES	303.4		322.0
INSURANCE & PROCUREMENT	5.2		5.4
TOTAL CONSTRUCTED COST	1144.8	1080.6	1168.7
SITE PREPARATION	11.2	11.2	11.2
DESIGN, ENGINEERING, OVERHEAD & FEE	156.8	150.2	164.6
PLANT FIXED CAPITAL	1312.8	1242.0	1344.5
CONTINGENCY, 15%	196.9	186.3	201.7
INITIAL CHARGE, CATALYSTS & CHEMICALS	12.3	7.4	13.6
PAID UP ROYALTIES	22.0	22.0	22.0
TOTAL PLANT INVESTMENT	1544.0	1457.7	1571.8

TABLE 4

COGAS PROCESS
250 BILLION BTU/DAY PIPELINE GAS
TYPICAL GAS PRICE CALCULATIONS
UTILITY-TYPE FINANCING
MID-1979 DOLLARS

	PITTS. SEAM	WESTERN SUBBITUMINOUS	ILLINOIS NO.6
	$MM	$MM	$MM
TOTAL PLANT INVESTMENT	1544.0	1457.7	1571.8
LAND	2.2	2.2	2.2
WORKING CAPITAL	44.3	37.3	47.2
CONSTRUCTION LOAN INTEREST	200.7	189.5	204.3
NET START-UP COSTS	21.6	6.0	24.0
TOTAL CAPITAL REQUIREMENT	1812.8	1692.7	1849.5
	$M/YR	$M/YR	$M/YR
COAL	171,600	87,680	192,570
CATALYSTS, CHEMICALS & UTILITIES	20,100	13,820	24,450
OPERATING COSTS	76,230	72,930	77,470
PLANT LEVEL COSTS	267,930	174,430	294,490
DEPRECIATION	88,425	82,770	90,115
INTEREST ON DEBT	119,380	111,464	121,800
INCOME AFTER TAX	66,322	61,924	67,667
FEDERAL INCOME TAX	61,220	57,161	62,462
SUB-TOTAL	335,347	313,319	342,044
REVENUE REQUIRED	603,277	487,749	636,534
REVENUE:			
NO. 2 FUEL OIL @ $21/BBL	49,203	41,060	86,279
No. 6 FUEL OIL @ $21/BBL	52,252	6,510	32,987
NAPHTHA @ $23/BBL	15,256	21,868	28,956
AMMONIA @ $120/TON	3,722	1,782	4,159
SULFURIC ACID @ $52/TON	27,588	9,480	37,589
PIPELINE GAS	455,256	407,049	446,564
TOTAL REVENUE	603,277	487,748	636,534

TABLE 5

SRC-I DEMONSTRATION PLANT PROJECT

COST FORECAST - DECEMBER 1979

(MILLIONS OF DOLLARS)

	FY80	FY81	FY82-84	TOTAL
PHASE I (DESIGN)(1)	37	65	66	168
PHASE II (CONSTRUCTION)(1)	12	143	955	1,110
PHASE IIIA (START-UP)(1)(2)	-0-	-0-	168	168
TOTAL	49	208	1,189	1,446

(1) CURRENT YEAR DOLLARS

10% ESCALATION FY 80
9% ESCALATION FY 81 AND BEYOND

(2) PHASE IIIA INCLUDES ONLY START-UP EXCLUSIVE OF REVENUES

TABLE 6

ECONOMICS OF KOPPERS TUTZEK GASIFICATION PROCESS

TOTAL CAPITAL REQUIREMENT

Bases: 15 gasifier plant (14 operating)
Bituminous Coal @ $20/Ton
"Grass-Roots" Plant

	Million $
Plant Investment	$367.00
Interest During Construction (9%/year x $367 MM x 1.875 yrs.)	61.93
Startup Costs (2% of Plant Investment)	7.34
Working Capital (60 day cash supply $=\frac{60}{300}$ x Gross Operating Cost)	17.80
Total Capital Requirement	$454.07

continued .....

TABLE 6 cont.:

GROSS AND NET OPERATING COSTS

BITUMINOUS COAL
FOURTEEN OPERATING GASIFIERS PLUS ONE SPARE
330 DAYS PER YEAR

ITEM	USAGE	UNIT COST	$M/YEAR	$/MM Btu
Coal	9702 tons/day	$20/ton	$64,033	$1.38
Catalysts and Chemicals	—	—	1,884	0.04
Raw Water (from river; treatment included in other costs)	10,500 gpm	no charge	0	0
Electricity, Incoming @ 138 kf	2.26MM kw-hr/day	15 mil/kw-hr	11,190	0.24
Process Operating Labor	96 people	$7.36/hr,*avg.	1,470	0.03
Supervision and Management	40 people	$9.50/hr,*avg.	790	0.02
Maintenance Labor	74 people	$7.80/hr,*avg.	1,200	0.03
Administrative Labor	30 people	$6.33/hr,*avg.	395	0.01
Contracted Maintenance Labor	1% of investment		3,670	0.08
Maintenance Materials	1.5% of investment		5,505	0.12
Operating Supplies	30% of process operating labor		440	0.01
Insurance and Local Taxes	2% of investment		7,340	0.16
Slag Disposal at Mine Site	2360 tons/day	$0.70/ton	545	0.01
Gross Operating Costs	—	—	$98,462	$2.13
Sulfur Credit	282 LT/day	$40.60/LT	(3,779)	(0.08)
Net Operating Cost			$94,683	$2.05

*Includes fringe benefits plus payroll extras

TABLE 7

COAL LIQUEFACTION PROCESS COMPARISON

	ENERGY COST $/MBTU	REFERENCE PRICE $/MBTU
DIRECT LIQUEFACTION-SOLID PRODUCT		
SRC-I	3.38	6.67
DIRECT LIQUEFACTION-LIQUID PRODUCT		
SRC-II	3.62	5.59
EDS	3.96	5.40
H-COAL FUEL OIL	3.30	5.09
H-COAL SYNCRUDE	3.58	4.81
INDIRECT LIQUEFACTION		
FISCHER-TROPSCH	4.99	5.52
M - GASOLINE	4.89	4.91
METHANOL	4.37	4.54

FIGURE 1   H Coal Process

PILOT PLANT BLOCK FLOW DIAGRAM

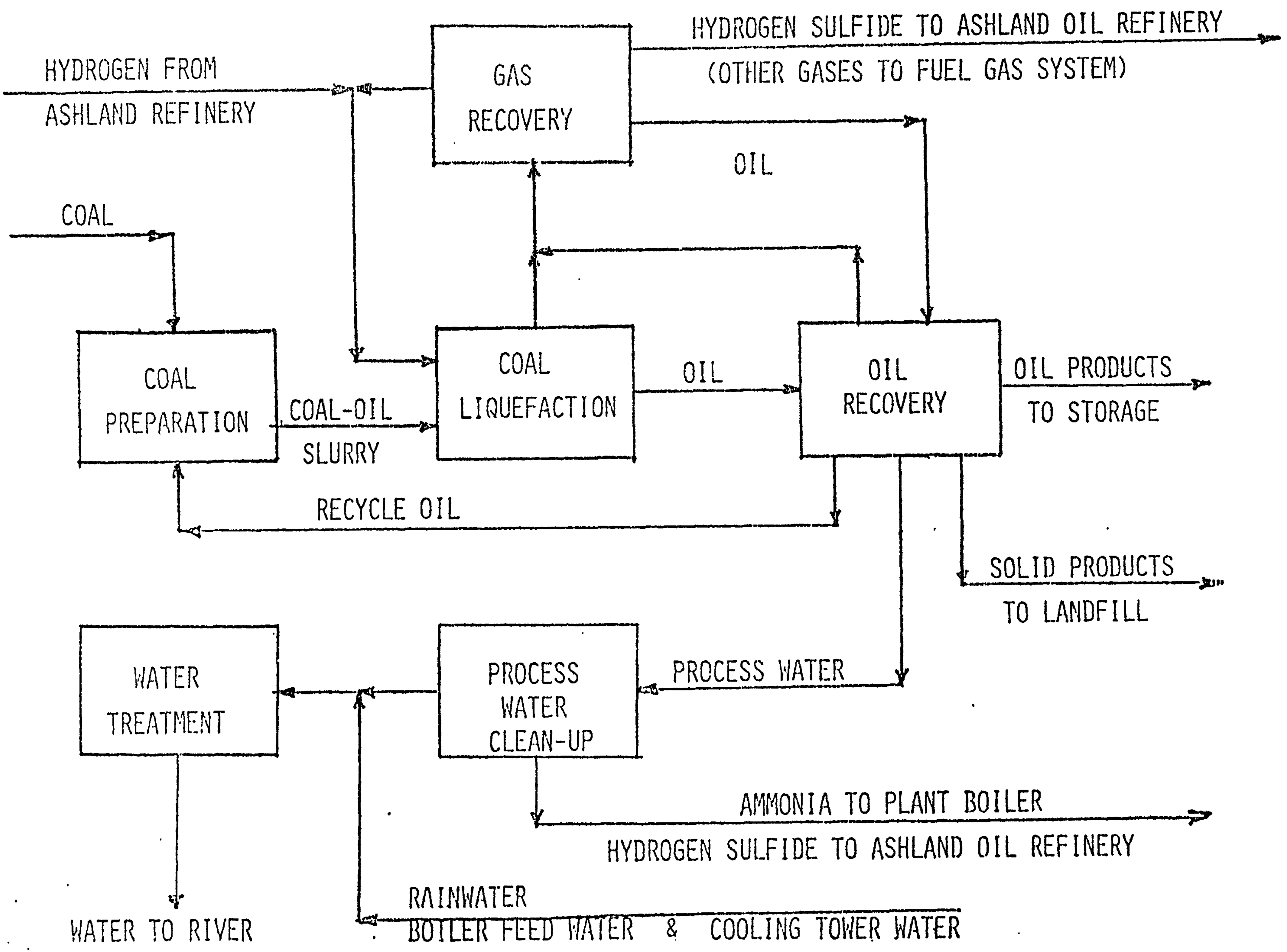


FIGURE 2

COGAS PROCESS

BLOCK FLOW DIAGRAM

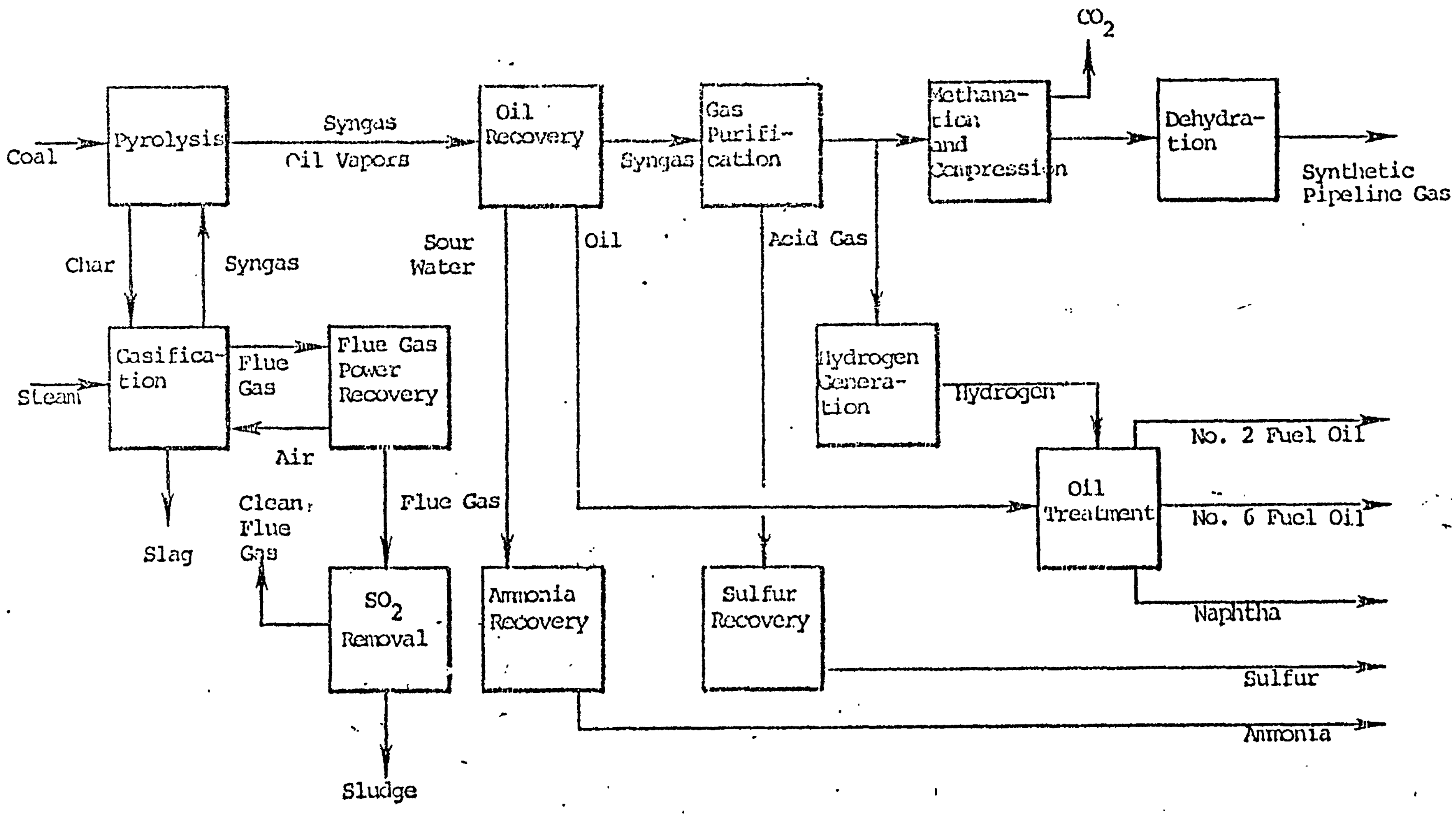


FIGURE 3

SOLVENT REFINED COAL

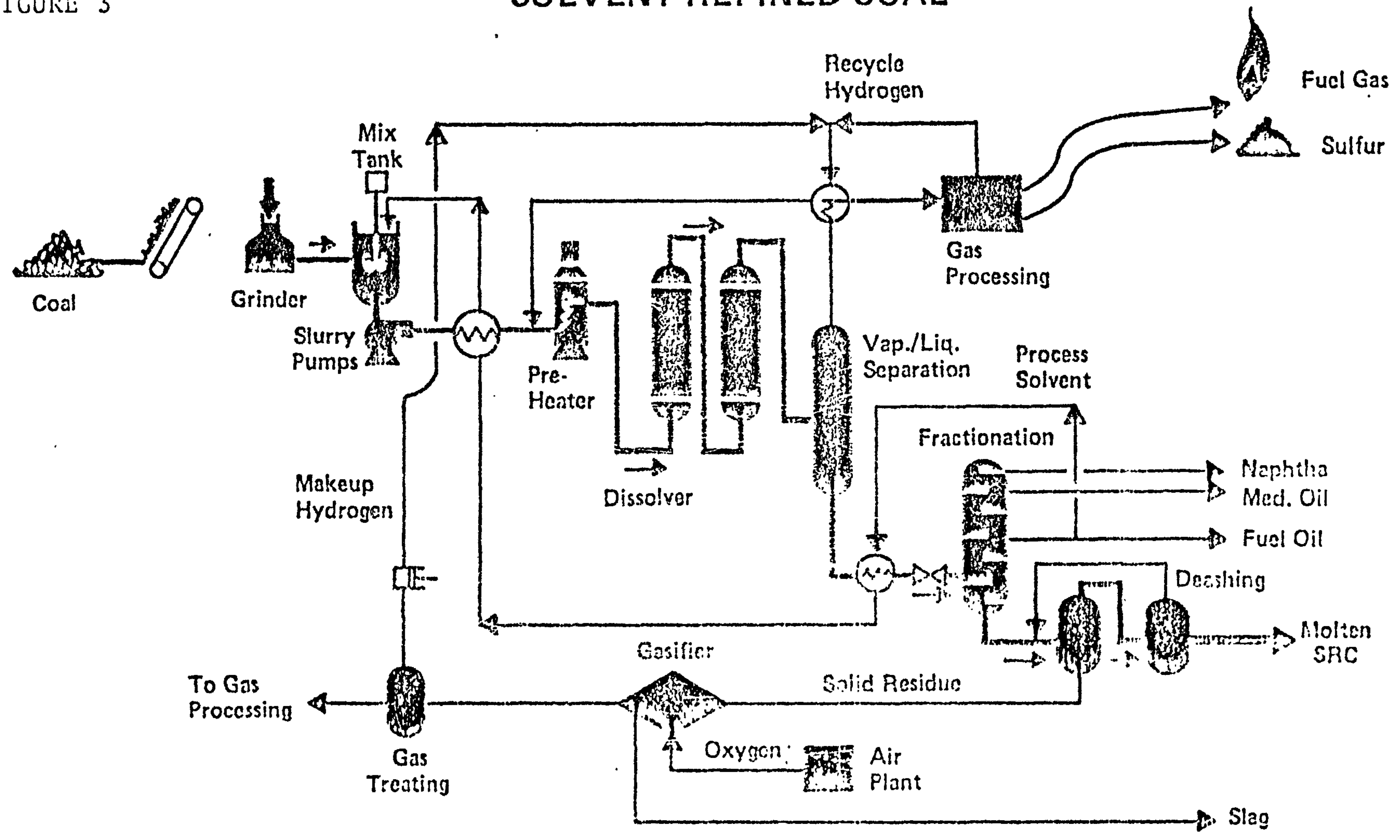


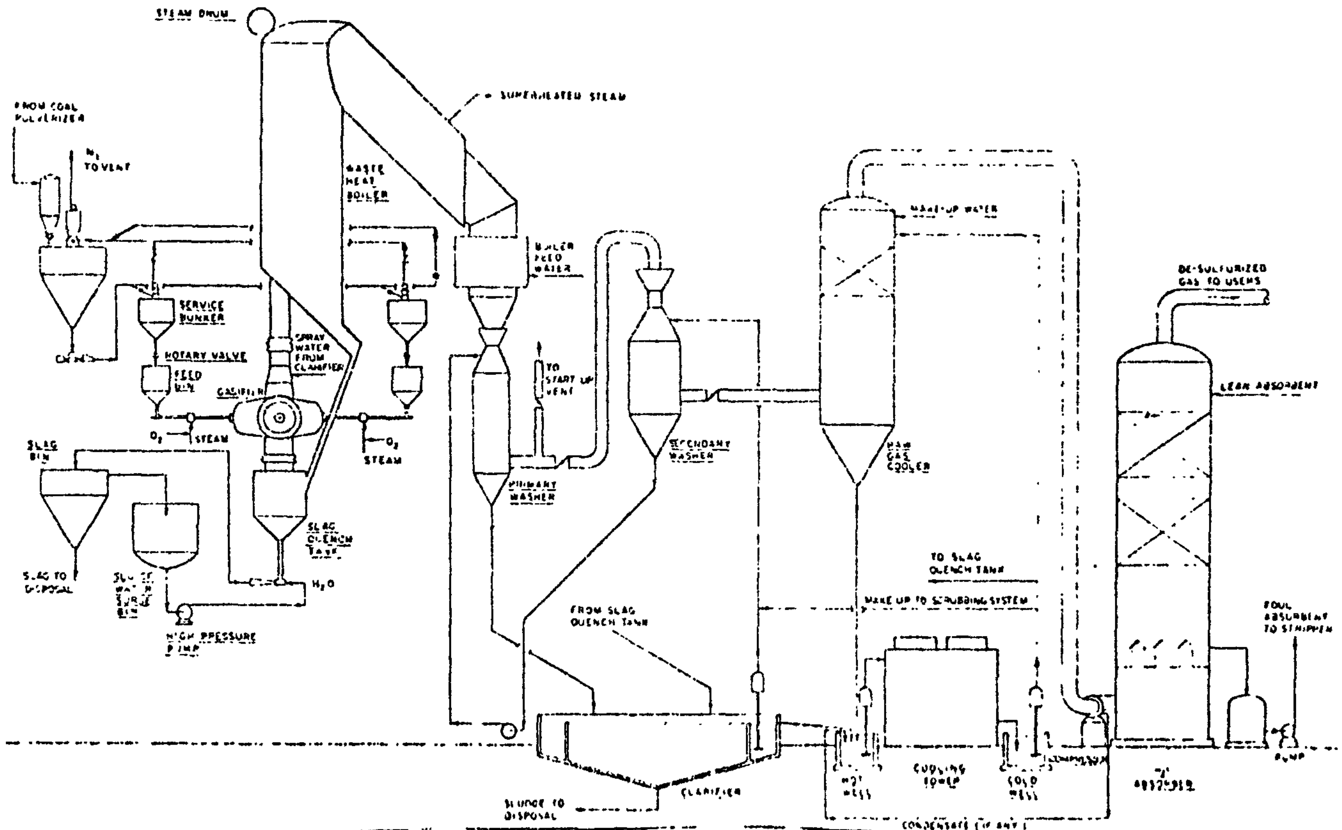
TABLE 9

Annualized SO_2 Emission Control Costs

Generating Station		Total Annual Operating Costs ($ millions)			
		1.2 lb of SO_2/ 10^6 Btu	1.6 lb SO_2/ 10^6 Btu	1.2 lb of SO_2/ 10^6 Btu	1.6 lb SO_2/ 10^6 Btu
Lingan	Unit 3 - 288 MW	7.1	6.2	4.2	3.7
	4 - 288 MW	7.1	6.2	4.2	3.7
Grand Lake New Unit	- 200 MW	13.4	13.4	11.6	11.6
Point Tupper	Unit 1A- 90 MW	2.2	1.9	4.2	3.7
	1B- 90 MW	2.2	1.9	4.2	3.7
	2 - 144 MW	3.6	3.2	4.2	3.7
Tufts Cove	Unit 1 - 96 MW	2.4	2.1	4.2	3.7
	2 - 96 MW	2.4	2.1	4.2	3.7
	3 - 144 MW	3.6	3.2	4.2	3.7
Dalhousie	Unit 1 - 105 MW	7.0	7.0	11.6	11.6
Courtenay Bay	Unit 1 - 50 MW	1.2	1.0	4.2	3.7
	2 - 13 MW	0.3	0.3	4.2	3.7
	3 - 100 MW	2.4	2.1	4.2	3.7
	4 - 100 MW	2.4	2.1	4.2	3.7
Coleson Cove	Unit 1 - 350 MW	8.6	7.6	4.2	3.7
	2 - 350 MW	8.6	7.6	4.2	3.7
	3 - 350 MW	8.6	7.6	4.2	3.7
Holyrood	Unit 1 - 141 MW	3.5	3.1	4.2	3.7
	2 - 141 MW	3.5	3.1	4.2	3.7
	3 - 141 MW	3.5	3.1	4.2	3.7
	4 - 141 MW	3.5	3.1	4.2	3.7

FIGURE 4

K—T GASIFICATION PROCESS



ALTERNATE COAL USE

by J. K. DAY

ALTERNATE COAL USE

A. Introduction

B. Background

C. Relevant Issues
  1. Coal type
  2. Product market
  3. Replacement considerations
  4. Technical feasibility
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Introduction

With the mining and use of Cape Breton coal a recognized necessity to the economic survival of the province, it is worthwhile to consider uses other than combustion feasible for application to this particular type of coal.

Any proposed alternate use should be demonstrated technically feasible, environmentally acceptable and economically favourable.

It is the purpose of this paper to suggest those areas where feasibility studies should be proposed for the purpose of demonstrating acceptable alternate uses of Cape Breton coal. It is not intended, at this point to consider details of alternate uses, but only to present suggestions which could be the basis of in-depth feasibility studies.

Background

Recent years have shown a renewed interest in mining and utilizing Atlantic Canada coal. Coal production has increased over the past five years, and ≈ 600 MW of coal fired electrical generating capacity have been added to the regional system.

A proposal for a unique coal preparation facility in New Brunswick has recently been developed through DREE and indications are that NSPC are planning to convert at least some of their oil fired capacity to coal firing.

The environmental implications of the combustion of coal coupled with the recognized economic advantages to a coal based industry, indicates the need for studies on the alternate uses of Atlantic coal to assess the feasibility of using R.O.M. and/or cleaned coal for uses other than combustion.

Relevant Issues

The following factors must be considered when developing feasibility studies for alternate coal use:

1. Coal type

The carbon, ash, and moisture content of coal are factors which could affect the choice of alternate use technology. Liquefaction and gasification processes are not universally applicable and only those amenable to a medium to high sulphur coal should be considered.

2. Product market.

Part of any feasibility study will have to include an analysis of the market conditions for products of liquefaction and/or gasification processes. Development of a petrochemical feedstock base industry is a possibility as well as sale of such feed stocks to areas where petrochemical production capability has already been established. Again, markets would have to be assessed.

Increased refining capacity for produced liquid fuels may have to be addressed as well as the possibility of infiltrating the domestic/industrial/commercial market with LPG.

3. Replacement considerations.

If an alternate coal use is developed, it could occur that electrical generating stations will have to be fired with fuel other than coal. A consideration of the replacement options for the present use of Cape Breton coal then would have to be part of a complete feasibility study.

Use of only excess mined capacity (i.e., coal mined in excess of that required for power generation) should also be considered.

4. Technical feasibility.

Only those liquefaction/gasification processes which have been demonstrated technically feasible should be considered. To conduct the research necessary to develop a technically feasible process would be too costly and too time consuming. In view of the fact that such research has been conducted by other institutions using similiar coal types negates the need to start feasibility analyses at the baseline technical level.

5. Environmental implications.

The environmental affects of coal liquefaction/gasification facilities will need to be addressed in any feasibility study. Indications are that atmospheric emissions from liquefaction/gasification facilities are not as environmentally objectionable as those from coal fired power plants. Some demonstrated technologies incorporate sulphur recovery and ammonia production from waste gasses thus reducing the environmental implication of SO_2 and NO_x emissions which occur as a result of combustion. Hot flue gasses can be used for process heat and those emissions which are not of acceptable quality can be purified using conventional technology. Liquid effluent discharges are practically eliminated in liquefaction/gasification facilities. Those contaminated process waters which are produced can be treated by conventional technology (i.e. sour water strippers, oil/water separators and biotreatment).

Solid waste from liquefaction/gasification processes consists of dry ash and/or slag which is easy to handle and amenable to land disposal.

Process Technology

The following processes have been considered and are suggested as possible candidates for in-depth feasibility studies:

1. H. Coal Process (See Figure 1)

H. Coal is a patented catalytic direct hydroliquefaction process developed by Hydrocarbon Research Incorporated. The process produces yeilds of low sulphur liquid distillates in the range of 40-50 weight per cent of feed coal.

The process has been demonstrated to be feasible using medium sulphur, sub bituminous coal and produces liquids suitable for use as boiler fuel; is a low H_2 consumer (therefore relatively cheap to run - $25-$45/BBL of fuel produced) and with technically proven up-grading processes (i.e., hydro treating, catalytic reforming hydro-finishing) yields of products like motor gasoline, home heating oil, diesel fuel and turbine fuel can be obtained.

Attractive features of this process with respect to Atlantic Canada coals include:

1. Any rank coal can be processed.
2. Exact sizing of feed coal is not required.
3. Coal fines may be fed.
4. Products produced can be varied from all distillate to predominatly heavy fuel oil.

Atmospheric emissions include:H_2S which can be recovered (other gasses go back to fuel gas system); process water contains sulfides, NH_3 and phenols which can be removed by sour water stripping followed by biological treatment; solid wastes include unconverted coal and ash suitable for landfilling.

2. COGAS Process (See Figure 2)

COGAS is a process designed to produce high BTU synthetic pipeline gas, fuel oil and naptha via pyrolysis and gasification of coal. The chief features of the process include pyrolysis of the feed coal (devolatilization of coal with heat), production of synthetic pipeline gas and fuel oil/naptha, and production of syngas (CO and H_2) from gasification and combustion of the pyrolysis char.

Features of this process which make it attractive to this region include:

a) Pyrolysis makes all coal types suitable for gasification and utilizes waste heat.

b) Complete coal-carbon utilization is achieved. (Even coal fines can be used as fuel).

c) Flue gas power recovery affects energy conservation and provides better environmental control.

d) Hydrotreating produces high quality, low sulphur liquids (i.e., naptha, No. 2 fuel oil, and No. 6 fuel oil).

e) Process is amenable to production of methanol, ammonia and petrochemicals.

Sulphur is removed from the flue gas and recovered; ammonia is removed and recovered from the waste liquor (oil treatment step) in a sour water stripper. Solid waste from the process consists of slag from the gasification unit and sludge from the SO_2 removal process.

3. SRC Process (See Figure 3)

Solvent Refined Coal (SRC) is a process developed for the production of liquid hydrocarbons (45% oil), solid solvent refined coal, anode coke and sulphur. It is a naptha solvent dehydrogenation process with 1:1.6 solvent to coal ratio where H_2 is donated to the coal. Gasification of the residue from the fractionation process is possible for H_2 production to be used upstream in the process.

Features of the process which make it attractive to this region include:

a) Process products are amenable for transportation fuel production (Gasoline yield from the SRC-Naptha approximates 97%).

b) Saleable solid products (calcined coke) are produced.

Emissions from an SRC plant are anticipated to be less than those from power plants by one order of magnitude; zero liquid effluent discharge is possible with evaporation of effluent (possible since effluent is only 1/5 of intake volume). Solid waste consists of process slag which has demonstrated minimum leaching in pilot tests (therefore, amenable to land disposal).

4. Koppers - Totzek Gasification Process

The K.T process involves partial oxidation of a carbonaceous feed in suspension with oxygen and steam to produce a medium BTU gas which can be readily desulphurized. Product gas is high in CO and H_2. The produced gas can be used without further processing for: 1) retrofitting existing gas-fired industrial heaters and boilers; 2) as a fuel for new units; 3) as a reducing gas for reduction of ferrous or non-ferrous ores; 4) process hydrogen production; and 6) synthesis of ammonia, methanol and SNG (methane). Such end uses require H_2S and particulate removal.

Features of the process which make it attractive with respect to regional applications include:

a) Any rank coal can be used.
b) Feed size is not a limiting factor.
c) Caking coals can be handled without pretreatment.
d) The process can be used to gasify the residues from coal liquefication processes to produce the necessary hydrogen.

Emissions are not expected to contain excessive amounts of pollutants since gas cleaning is incorporated in process design. Gas cleaning water has some ammonia and cyanides which can be stripped out and combusted. Particulates in waste water can be removed in a clarifier. Solid by-products include saleable elemental sulphur and a granulated slag suitable for landfill.

Other coal conversion processes are available and have been demonstrated technically feasible at least on a pilot scale. Any feasibility study should incorporate a literature review of available technologies.

Economics

All coal conversion technology is complex and highly investment intensive. Typically 50-70% of the product cost is investment related as compared to 20-30% for conventional petroleum refining. Also, from 30-50% of the feed energy content is consumed in processing (30% for direct hydroliquefaction processes like H-Coal and 50% for indirect processes like Lurgi and Fisher Tropsch).

1. H-Coal

Table 1 shows H-Coal Liquefaction plant base case data used in a linear programming model. The model optimizes process configurations, operating conditions and product options for a complete plant.

The model has been used to screen studies for commercial plant design and economics and incorporates process yields, utilities, investments and operating costs for all individual units on a consistent basis. Table 2 shows an LP model printout for a hypothetical 25,000 TPD plant. In summary, the model indicates a total capital requirement of $\$1.5\text{x}10^9$, annual operating costs of $\$.702\text{x}10^9$, annual revenues of $\$.687\text{x}10^9$ with a resultant negative net cash flow. The results of course are specific to the data fed into the model and subject to wide variations depending on costs of coal, power, labor, interest rates, product revenues. Optimizing such process variables to provide a profit-making plant would be the first task before a "go"/"no go" decision could be made.

2. COGAS

Economics for a 20000 TPD Co Gas processing plant producing $250\text{x}10^9$ BTU/day pipeline gas is presented in Tables 3 and 4. Total plant investment approximates $\$1.5\text{x}10^9$ (similar to the H-Coal plant). However, annual operating costs and revenues are very nearly equal resulting in a break-even situation due primarily to the higher value of Co Gas process products. Again, the economic evaluations are theoretical and based on projected cost data and revenues. For the purpose of comparison, Co Gas economics look more favourable than H-Coal.

3. SRC

Economics of the SRC process have not been well defined since design work has focused on demonstration units not exceeding a 6000 T/D capacity. Table 5 shows projected costs for design, construction and startup of a 6000 T/D demonstration plant which shows a capital requirement of $\$1.2\text{x}10^6$.

4. Koppers Totzek

A summary of the economics of a 9000 TPD capacity K.T. gasification plant is presented in Table 6. The initial capital investment is less than that indicated for liquefaction facilities. However, the viability of the process depends on the market being receptive to the produced pipeline gas. Production of one major commodity reduces the flexibility of the process and influences the economics.

Energy Costs

A comparison of the energy costs for the processes previously discussed is presented in Table 7. The table contains energy costs at 25000 TPD plants with the reported reference price reflecting cost of products based on current market price (with gasoline at a reference value of 1. If a plant were producing pure gasoline, there would be no adjustment). The costs are relative ones and demonstrate that the direct liquefaction processes are more energy efficient.

Summary

Four processes representative of current coal conversion technology have been described here in terms of process design, applicability and economics. Liquefaction/ gasification processes have been demonstrated to be technically feasible and some processes are in commercial use. However, considering the high capital expenditures required for plant construction as well as the variable economics of plant operations (in terms of market potential, raw material costs, power and labor), it seems that coal conversion infiltration of the Atlantic Canada coal scene is at least 10 years away.

However, feasibility studies into the economic and environmental implications of coal conversion processes should be conducted to document those areas where liquefaction/ gasification technology could be a viable alternative to coal combustion.

References

Current Coal Conversion Process Technology, - The Center for Professional Advancement. East Brunswick, New Jersey, 08816.

TABLE 1

H-COAL LP MODEL

H-COAL LIQUEFACTION BASE CASE

YIELDS	T/T MAF COAL	TO/FROM
MAF COAL	(1.0000)	FROM COAL PREPARATION
MAKEUP HYDROGEN	(0.0691)	FROM HYDROGEN COMPRESSION
PURGE HYDROGEN	0.0084	TO PROCESS FUEL
H_2S TO GAS TREATING	0.0106	TO GAS TREATING
H_2S TO SULFUR RECOVERY	0.0191	TO SULFUR RECOVERY
CO_2	0.0081	TO GAS TREATING
C_1/C_2	0.0806	TO PROCESS FUEL, GAS PRODUCT
C_3	0.0269	TO LIGHT ENDS RECOVERY
C_4	0.0220	TO LIGHT ENDS RECOVERY
$C_5/400^{\circ}F$	0.2342	TO PROCESS FUEL, TANKAGE OR PARTIAL OXIDATION FOR H_2
$400/650^{\circ}F$	0.1744	
$650/975^{\circ}F$	0.1088	
$975^{\circ}F+HC$	0.2746	TO PARTIAL OXIDATION FOR H_2
NH_3	0.0109	TO SALES
SOUR WATER	0.7421	TO SOUR WATER TREATING
CO	0.0014	TO PROCESS FUEL,

QUALITIES

	S.G.	S, WT%	N, WT%	LHV MBTU/T	HHV MBTU/T
$C_5/400$	0.786	0.05	0.12	36.60	39.18
400/650	0.913	0.06	0.13	34.63	36.50
650/975	1.073	0.20	0.64	32.71	34.05
975+ HC	1.285	3.40	1.49	28.39	29.11

UTILITIES

COOLING WATER	3.206	T/T MAF COAL PLUS ASH
TURBINE POWER	16.80	KWH/T MAF COAL PLUS ASH
ELECTRIC POWER	36.59	KWH/T MAF COAL PLUS ASH
STEAM -600 PSIG(OUTPUT)	0.0092	T/T MAF COAL PLUS ASH
STEAM - 75 PSIG(OUTPUT)	0.1663	T/T MAF COAL PLUS ASH
PROCESS FUEL (LHV)	0.4006	MBTU/T MAF COAL PLUS ASH
RAW WATER, PURCHASED	0.00786	KGAL/T MAF COAL PLUS ASH

TABLE 1. cont. ....

TABLE 1 continued:

INVESTMENTS

DIRECT MATERIAL	(1979 $)	171.844	M $
DIRECT LABOR	(1979 $)	44.494	M $
SERVICE FACTOR		90	%
BLOCK SIZE		25,000	T/SD MAF COAL PLUS ASH
SIZE COMPONENT		0.80	

OPERATING COSTS (1979 $)

CATALYST AND CHEMICALS COSTS	2.20	$/T MAF COAL PLUS ASH
LABOR, SUPERVISION & OVERHEAD	1.10	% TEC/YR
MAINTENANCE	5.0	% TEC/YR

0154166

An air emission guideline for new coal generating stations where federal funding is involv